AMPCO INTERROGATORY #1

Reference:

A-03-01 p.13

Interrogatory:

Please discuss any changes to Hydro One's strategic priorities since EB-2016-0160.

Response:

Strategic priorities were not included in the previous application. Hydro One's current strategic priorities are included in Exhibit B, Tab 1, Schedule 1, Section 2.1, page 5. Please refer to Exhibit I, Tab 12, Schedule AMPCO-002 for a discussion of changes to Transmission Business Values and Objectives.

Witness: Joel Jodoin, Bruno Jesus

AMPCO INTERROGATORY #2

Reference:
A-03-01 p.13

Interrogatory:
Please discuss any changes to Hydro One’s business values and objectives since EB-2016-0160.

Response:
The table below shows Hydro One’s Business Values and Objectives included in the current application and those included in the prior application:

		Current Application EB-2019-0082 – A-3-1, page 15	**Prior Application EB-2016-0160 – A-3-1, page 4**
Customer Focus	**Customer Satisfaction**	• Improve current levels of customer satisfaction	• Improve current levels of customer satisfaction
	Customer Focus	• Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers’ needs and desired outcomes	• Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers’ needs and desired outcomes
Operational Effectiveness	**Cost Control**	• Actively control and lower costs through OM&A and capital efficiencies	• Actively control and lower costs through OM&A and capital efficiencies
	Safety	• Drive towards achieving an injury-free workplace	• Drive towards achieving an injury-free workplace
	Employee Engagement	• Achieve and maintain employee engagement	• Achieve and maintain employee engagement
	System Reliability	• Provide top quartile reliability relative to transmission peers	• Maintain top quartile reliability relative to transmission peers

Witness: Joel Jodoin, Bruno Jesus

Public Policy Responsiveness	**Public Policy Responsiveness**	• Ensure compliance with all codes, standards and regulations • Partner in the economic success of Ontario	• Ensure compliance with all codes, standards and regulations • Partner in the economic success of Ontario
	Environment	• Sustainably manage our environmental footprint	• Sustainably manage our environmental footprint
Financial Performance	**Financial Performance**	• Achieve the ROE allowed by the OEB	• Achieve the ROE allowed by the OEB

The only change in the stated business values and objectives is to System Reliability, which has been updated to reflect recent transmission performance and the intent to improve reliability and return to top quartile performance.

AMPCO INTERROGATORY #3

Reference:
A-03-01 p.28

Interrogatory:
Hydro One indicates the asset analytics system enables Hydro One planners to review aggregated information from various enterprise reporting systems.

Please list the enterprise reporting systems that are currently used and advise of any changes since EB-2016-0160.

Response:
Asset Analytics currently uses the following enterprise reporting systems:

- AMI – This database has replaced DGFIT
- ORMS – Outage Response Management System
- GIS (TLGIS/FDGIS) – This data provides the geo-spatial information of the line/circuit Assets
- TODS – Transmission Outage Data System
- DPP – Delivery Performance Point: This database provides the reliability of each Delivery Point for the Tx system
- NMS – Network Management System: This database provides loading information and certain data relationship information for Tx Assets
- PSDB – Power System DataBase: This database it used for a number of Asset relationship and some operation related information
- TOA – Transformer Oil Analysis: The dissolved gas analysis coming from Morgan Shaffer is loaded into SAP and tracks Transformer condition

There are no changes to the systems, since the prior proceeding. AMI has replaced DGFIT but the data has not changed.

Witness: Bruno Jesus, Donna Jablonsky

AMPCO INTERROGATORY #4

Reference:
A-03-01 p.29

Interrogatory:
a) Please confirm the six risk factors are consistent with EB-2016-0160.

b) Please provide the relative weightings for each risk factor.

Response:
a) Confirmed.

b)

	Condition	Demographics	Criticality	Utilization	Performance	Economics
Conductors	40%	15%	15%	15%	15%	N/A
Transformers	33%	11%	7%	13%	27%	9%
Breakers	33%	11%	7%	13%	27%	9%

Witness: Bruno Jesus

AMPCO INTERROGATORY #5

Reference:

A-03-01 p.30

Interrogatory:

Please provide a list of Hydro One's key transmission asset types from the highest value to lowest value.

Response:

Please refer to Exhibit F, Schedule 6, Tab 1, Attachment 1, 2017 Depreciation Rate Review, Statement E, attachment p. 18. Hydro One's key transmission asset types are listed under the Uniform System of Accounts (USoA) 1715 Station Equipment and USoA 1730 Overhead Conductors and Devices.

For additional details, please also refer to Exhibit C, Schedule 4, Tab 4, Append 2-BA, Fixed Asset Continuity Schedules for the values by USoA.

Witness: Samir Chhelavda, Bruno Jesus

AMPCO INTERROGATORY #6

Reference:
A-03-01 p.32

Interrogatory:
Under step 2, Candidate Investment Development, please confirm the number of candidate investments identified at this step compared to the number developed and submitted for possible inclusion in the investment plan.

Response:
Refer to Interrogatory I-07-SEC-27.

Witness: Bruno Jesus

AMPCO INTERROGATORY #7

Reference:
A-03-01 p.39

Interrogatory:
Please provide the reductions in costs attributable to a reduction in vacancies and provide the calculation and assumptions.

Response:
Please see Exhibit I, Tab 01, Schedule OEB-182.

AMPCO INTERROGATORY #8

Reference:
A-03-01 p.40

Interrogatory:
Hydro One indicates its maintenance reduction has included reductions in activities including a one year extension of planned maintenance and asset condition assessments and represents a managed increase in asset risk that may manifest in terms of increased corrective/demand failures and/or reduced asset useful life that can be contained with a one year reduction in work and will be managed and mitigated in future years.

Please discuss how this managed asset risk was evaluated and measured.

Response:
The 2019 maintenance reduction was based on work programs that posed the lowest risk. The risk was evaluated based on the impact to public safety, system reliability and the environment. The risk was measured using the taxonomy described in Exhibit B-1-1 TSP-02-01, Section 2.1.4.1 on Investment Assessment.

Witness: Donna Jablonsky

AMPCO INTERROGATORY #9

Reference:
A-03-01 p.42 Table 10

Interrogatory:
Please expand Table 10 to include the years 2014 to 2018.

Response:
Please refer to Exhibit I, Tab 07, Schedule SEC-58.

Witness: Sabrin Lila

AMPCO INTERROGATORY #10

Reference:
A-03-01-01

Interrogatory:
a) Please confirm when the 2019-2024 Transmission Business Plan was approved by the Board of Directors.

b) Please provide any subsequent communication with Hydro One's Board of Directors regarding the Plan.

Response:
a) The 2019-2024 Transmission Business Plan was approved by the Board of Directors on December 14, 2018.

b) Please see Exhibit I, Tab 07, Schedule SEC-002 for subsequent communication with Hydro One's Board of Directors regarding the Plan.

AMPCO INTERROGATORY #11

Reference:
A-05-01-02

Interrogatory:
With respect to Hydro One’s Executive Organization Structure, please discuss the need, scope, timing and cost impact of any organizational restructuring that has taken place since 2017 or is planned for the test period.

Response:
Hydro One’s organizational structure has evolved over time to reflect the changing needs of the organization and its stakeholders. Since 2017, the organizational structure has remained largely constant. Please refer to Exhibit I, Tab 11, Schedule 3 for the most recent Organizational Chart. As described in Exhibit F, Tab 4, Schedule 1 pages 34-36 the compensation costs for the President and CEO and the Executive Leadership Team have been removed from the revenue requirement.

AMPCO INTERROGATORY #12

Reference:
A-06-02

Interrogatory:
Please provide the 2017 and 2018 Hydro One Networks Inc. Transmission Business Financial Statements.

Response:
2017 and 2018 Hydro One Networks Inc. Transmission Business Financial Statements were filed as part of the Blue Page Update. Please refer to Exhibit A, Tab 6, Schedule 2, Attachments 3.

Witness: Samir Chhelavda

AMPCO INTERROGATORY #13

Reference:

A-06-06

Interrogatory:

Please provide the 2018 Annual Report.

Response:

The 2018 annual report was filed in the Blue Page Update submission. Please refer to Exhibit A, Tab 6, Schedule 6, Attachment 2.

Witness: Samir Chhelavda

AMPCO INTERROGATORY #14

Reference:

EB-2016-0160 Exhibit I-03-001 Attachment 4

Interrogatory:

a) Please provide a list of the Audit Reports Issued in 2016, 2017, 2018 and 2019 to date.

b) Please provide the Final Audit Plan for 2019 to 2020.

Response:

Please see I-07-SEC-006.

Witness: All Witnesses

AMPCO INTERROGATORY #15

Reference:

TSP-01-04 p.1 and 29, TSP-01-04-13

Interrogatory:

HONI's evidence at Page 1 includes benchmarking studies and third party assessments that help inform Hydro One of the condition of its assets and how to effectively and efficiently manage those assets. This includes a "Review of Hydro One's capabilities in Transmission Asset Analytics and Reliability Risk Modelling" (Attachment #13). At Page 29 (Table 20), Hydro One provides the Asset Analytics Methodology Recommendations.

Please provide a status report on Hydro One's progress regarding implementation of these recommendations.

Response:

Please refer to Interrogatory I-01-OEB-78.

AMPCO INTERROGATORY #16

Reference:
TSP-01-04 p.7

Interrogatory:
From Hydro One's perspective, please confirm the purpose and analysis implications of the Reliability Risk Model, historically and now.

Response:
The Reliability Risk Model ("RRM") is a simplified communication tool to communicate relative outcomes to customers. It is not used to select investments. Asset needs are anchored by asset condition assessments and investments are justified by asset needs and prioritized in accordance with Hydro One's investment planning approach. Please refer to Exhibit B-1-1 TSP 1.3 Attachment 4 for further information about the RRM.

AMPCO INTERROGATORY #17

Reference:
TSP-01-04 p.13

Interrogatory:
Hydro One indicates the final results of the ESL Assessment of Specific Relays study was not available at the time of the filing of the rate application.

Please indicate when the final report will be available or file the study if available.

Response:
The Kinectrics Report on ESL Assessment of Specific Relays may be found at Exhibit B-1-1 TSP 1.4 Attachment 16.

AMPCO INTERROGATORY #18

Reference:
TSP-01-05 p.5

Interrogatory:

a) Please provide a copy of Hydro One's Transmission final Scorecard from EB-2016-0160.

b) Please provide a list of measures that are new to the scorecard compared to EB-2016-0160.

c) Please provide a list of measures that have been removed from the scorecard compared to EB-2016-0160 and explain why.

Response:

a) Hydro One proposed a Transmission Scorecard in EB-2016-0160, Exhibit B2-1-1, Attachment 1, p.2, replicated below as Figure 1. In the OEB's Decision and Order[1], the OEB did not consider it necessary to approve Hydro One's proposed Transmission Scorecard at that time and directed Hydro One to continue to develop its scorecard to reflect the Findings in the Decision and Order as related to the Transmission Scorecard. As such, Hydro One did not have a *final* Transmission Scorecard resulting from EB-2016-0160, but rather a draft Transmission Scorecard.

b) The following measure are new to the Evolved Electricity Transmitter Scorecard proposed by Hydro One in Exhibit B-1-1, TSP Section 1.5, p.5, Figure 1:
   a. Transmission System Implementation Progress (%)
   b. OM&A Program Accomplishment (composite index)
   c. Capital Program Accomplishment (composite index)
   d. Line Clearing Cost per kilometer ($/km)
   e. Brush Control Cost per Hectare ($/Ha)
   f. End-of-Life Right Sizing Assessment Expectation

[1] Decision and Order EB-2016-0160, Revised November 1, 2017, s.5.0 Productivity Improvements and Performance Scorecard, p.38

Witness: Bruno Jesus

c) The following measures were removed from the proposed Transmission Scorecard filed in EB-2016-0160:
    a. In-Service Capital Additions (% of OEB approved plan)
    b. Sustainment Capital per Gross Fixed Asset Value (%)
    c. NERC/NPCC Reliability Standards Compliance
        i. Number of High Impact Violations
        ii. Number of Medium/Low Impact Violations

These measures were removed from the proposed Transmission Scorecard in response to the OEB's Findings[2]. For a detailed explanation outlining the process for removing and replacing these measures and how Hydro One responded to the OEB's Findings regarding the Transmission Scorecard, please refer to Exhibit B-1-1, TSP Section 1.5, *Response to OEB Directions* from EB-2016-0160, pp.10-19.

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[2] Ibid, p.39

Performance Outcomes	Performance Categories	Measures	Historical Years 2011	2012	2013	2014	2015	Trend
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	Satisfaction with Outage Planning Procedures (% Satisfied)	Note 1	78	Note 1	86	92	▲
		Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs	13.8	10.8	12.8	11.8	Note 2	▲
	Customer Satisfaction	Overall Customer Satisfaction in Corporate Survey (% Satisfied)	85	76	81	77	85	-
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Recordable Incident Rate (# of recordable injuries/illnesses per 200,000 hours worked)	3.7	2.3	2.5	1.8	1.7	▲
	System Reliability	T-SAIFI-S (Ave. # Sustained Interruptions per Delivery Point)	0.60	0.61	0.57	0.60	0.59	-
		T-SAIFI-M (Ave. # Momentary Interruptions per Delivery Point)	0.60	0.65	0.69	0.48	0.50	▲
		T-SAIDI (Ave. Minutes of Interruptions per Delivery Point)	127.9	71.5	66.0	36.6	44.3	▲
		System Unavailability (%)	0.50	0.48	0.37	0.48	0.66	▼
		Unsupplied Energy (minutes)	21.6	14.0	20.9	12.2	11.8	▲
	Asset Management	In-Service Capital Additions (% of OEB approved plan)	95	75	90	106	85	▲
		CapEx as % of Budget	78	81	73	90	106	▲
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)	9.8	8.6	7.6	8.4	9.0	▲
		Sustainment Capital per Gross Fixed Asset Value (%)	2.6	2.8	3.3	4.2	4.6	Note 3
		OM&A per Gross Fixed Asset Value (%)	3.4	3.0	2.7	2.7	2.9	▲
Public Policy Responsiveness Transmitters deliver on obligations mandated by government. (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board)	Connection of Renewable Generation	% on time completion of renewables connection impact assessments	100	100	100	100	100	-
	Market Regulatory Compliance	NERC/NPCC Reliability Standards Compliance						
		- Number of High Impact Violations (Note 4)	N/A	N/A	N/A	20	2	
		- Number of Medium/Low Impact Violations (Note 4)	N/A	N/A	N/A	5	10	
	Regional Infrastructure	Regional Infrastructure Planning progress - % Deliverables met	N/A	N/A	N/A	100	100	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.24	0.29	0.80	0.69	0.13	
		Leverage: Total Debt (includes short-term & long-term debt) to Equity Ratio	1.27	1.22	1.10	1.16	1.39	
		Profitability: Regulatory Return on Equity — Deemed (included in rates) (%)	9.66	9.42	8.93	9.36	9.30	
		Profitability: Regulatory Return on Equity — Achieved (%)	10.95	12.41	13.22	13.12	10.93	

Note 1: Customer Satisfaction survey not done in 2011 and 2013.
Note 2: Results will be available in July 2016.
Note 3: In 2014 strategic decision made to increase sustainment capital.
Note 4: Results from 2011 to 2013 are excluded due to a lack of consistant data compared to 2014 and 2015.

Legend:
▲ up
▼ down
- flat

Figure 1 – Proposed Transmission Regulatory Scorecard – Hydro One Networks Inc., EB-2016-0160

AMPCO INTERROGATORY #19

Reference:

TSP-01-05-01 p.4

Interrogatory:

Please provide the monthly Compensation Team Scorecard for the past 6 months.

Response:

The compensation team scorecard is the as the corporate team scorecard. As the monthly team scorecard includes confidential company information governed by securities regulations including financial and operational performance that have not been publicly disclosed or audited we are unable to provide the requested information.

Attached is the 2018 Corporate Team Scorecard, as disclosed in Hydro One's most recent Management Information Circular.

Exhibit F, Tab 4, Schedule 1 Attachment 4 details the team performance measures and specific objectives in place for 2019.

Witness: Bruno Jesus, Sabrin Lila

2018 Team Scorecard

As disclosed in most recent Management Information Circular.

Component	Measure	Performance Levels and Actual Achievement (◇ represents Hydro One 2018 Achievement)	Weighting	Percentage Achievement	Contribution to Team Scorecard
Health & Safety					
Recordable Incidents	Recordable Incidents per 200,000 hours	Threshold: 1.30; Target: 1.10; Max: 1.00; Actual: 1.11	10.00%	93.85%	9.39%
Work Program					
Tx Reliability	Minutes per Delivery Point (SAIDI)	Thresh.: 9.20; Target: 7.60; Max: 5.40; Actual: 15.37	6.25%	0.00%	0.00%
Dx Reliability	Hours per Customer (SAIDI)	Threshold: 7.50; Target: 7.00; Max: 6.80; Actual: 6.82	6.25%	190.00%	11.88%
Tx In Service Capital	Variance (%) to approved budget of $1,174M	Thresh.: +/-6.00%; Target: +/-4.00%; Max: +/-1.00%; Actual: -1.16%	6.25%	194.65%	12.17%
Dx In Service Capital	Variance (%) to approved budget of $641M	Thresh.: +/-5.00%; Target: +/-3.00%; Max: +/-1.00%; Actual: -4.23%	6.25%	83.99%	5.25%
Financials					
Net Income	Net Income to Common Shareholders - $M	Threshold: 660.71; Target: 705.79; Max: 756.71; Actual: 806.67	30.00%	200.00%	60.00%
Productivity					
Productivity Savings	Productivity Savings - $M	Threshold: 103.10; Target: 114.50; Max: 140.00; Actual: 135.51	10.00%	182.40%	18.24%
Customer Service					
Dx Satisfaction: Small & Residential Customers	Dx Customer Satisfaction (SMB & Res.)	Thresh.: 71.00%; Target: 73.00%; Max: 76.00%; Actual: 76.00%	12.50%	200.00%	25.00%
Tx Satisfaction: Large Customers	Tx Customer Satisfaction (Large Cust.)	Thresh.: 84.00%; Target: 86.00%; Max: 90.00%; Actual: 90.00%	12.50%	200.00%	25.00%
Total					**166.91%**

AMPCO INTERROGATORY #20

Reference:
TSP-02-01 p.10

Interrogatory:
Please add the years 2015 to 2019 to Table 1 – Forecast of Transmission Charge Determinants.

Response:
Please see table below for the requested information.

Forecast of Transmission Charge Determinants
(12-month average peak in MW)

Year	Network	Change (%)	Line Connection	Change (%)	Transformation Connection	Change (%)
2015	20,236	-1.8	19,576	-0.3	16,731	-0.5
2016	20,245	0.0	19,540	-0.2	16,715	-0.1
2017	19,705	-2.7	19,100	-2.3	16,306	-2.4
2018	19,678	-0.1	19,137	0.2	16,329	0.1
2019	19,614	-0.3	19,078	-0.3	16,258	-0.4
2020	19,604	0	19,071	0	16,252	0
2021	19,469	-0.7	18,941	-0.7	16,142	-0.7
2022	19,322	-0.8	18,800	-0.7	16,021	-0.7

Witness: Bijan Alagheband

AMPCO INTERROGATORY #21

Reference:

TSP-02-01 p.40

Interrogatory:

Please add dates to Figures 15, 16, 17 and 18.

Response:

Refer to Interrogatory I-07-SEC-007.

Witness: Bruno Jesus

AMPCO INTERROGATORY #22

Reference:
TSP-02-01 p.45

Interrogatory:
With respect to Monitoring and Control, Hydro One indicates variances from the plan are identified and managed through a variance and redirection process.

a) Please provide Hydro One's threshold variance limits with respect to cost, scope and schedule.

b) Please provide the forecast number of projects compared to actuals for each of the years 2016 to 2018.

c) Please provide the number of projects deferred, cancelled and moved forward from future years for each of the years 2016 to 2018.

d) Please provide the number of cost variance reports and total dollar amount for each of the years 2016 to 2018.

e) Please provide the number of schedule variance reports and total days for each of the years 2016 to 2018.

f) Please provide the number of scope variance reports and total dollar amount for each of the years 2016 to 2018.

Response:

a) The variance limits are outlined in Table 1 below.

Table 1: Variance Limits

Variance Type	Limit
Cost	Cost Variances are calculated in gross dollars where: 1. Variance in expenditures is more than $5 million; or 2. Variance greater of 10% of currently approved expenditures and greater than $0.5 million
Scope	A Project or Program is deemed to have variance in scope if either of the following events occur: 1. The deliverables are modified; or 2. Planning Specifications at the functional or performance levels are modified.
Schedule	Schedule variances are business impactive changes to planned In-Service dates. Business impactive schedule variances are those that materially affect the value or benefit of the scope of work. Examples include: • Missing critical commitments to customers, external stakeholders or the Board of Directors. • When the delay will require a material adjustment to the annual work plan

b) Table 2 below outlines the forecast number of project awarded for execution and actual number of projects awarded for execution for the years of 2016 to 2018.

Table 2: Annual Number of Projects

	2016	2017	2018	Total
Number of Forecast Projects	70	52	103	225
Number of Actual Projects	114	135	116	365
Variance	44	83	13	140

c) Refer to the response provided for I-12-AMPCO-022 part E.

d) The number of cost variance reports and the associated dollar amounts for 2016 to 2018 are outlined in Table 3 below.

Table 3: Cost Variance Reports from 2016 to 2018

	2016	2017	2018	Total
Number of Cost Variance Reports	26	29	28	**83**
Total Amount of Variance (Millions)	66.1	(59.2)	2.7	**9.6**

e) The number of schedule variance reports and the associated days of variance for 2016 to 2018 are outlined in Table 4 below.

Table 4: Schedule Variance Reports from 2016 to 2018

	2016	2017	2018	Total
Number of Schedule Variance Reports	**17**	**12**	**7**	**36**
Projects Deferred	16	12	6	**34**
Projects Cancelled	0	0	0	**0**
Projects Moved Forward	1	0	1	**2**
Total Amount of Variance (Days)	**11,019**	**10,319**	**2,095**	**23,433**

f) The number of scope variance reports and the associated dollar amounts for 2016 to 2018 are outlined in Table 5 below.

Table 5: Scope Variance Reports from 2016 to 2018

	2016	2017	2018	Total
Number of Scope Variance Reports	7	10	12	**29**
Total Amount of Variance (Millions)	13.5	(10.7)	29.3	**32.1**

AMPCO INTERROGATORY #23

Reference:
TSP-02-01 p.45

Interrogatory:
Please provide the key internal metrics that Hydro One uses to project/program track cost, schedule and scope variances.

Response:
Hydro One has a structured monthly process to review cost, schedule and scope variances for each project / program that is in execution. This involves monthly reviews / updates of forecasts by project managers followed by cascading reviews by the management team. Every effort is made to deliver to plan, with exceptions flagged and reviewed. On a quarterly basis, reporting to the executive includes performance for key projects and we are in the process of implementing refined cost and schedule metrics to be regularly reported to the executive.

Variances that cannot be reversed are documented based on the below thresholds.

Cost Variance

- ***Variance Initiation***: Variance documentation is initiated when >80% of released amount is spent and current forecast meets variance criteria (i.e. [>10% variance to release and >$500K variance to release] or >$5M variance to release).

Schedule Variance

- ***Variance Initiation***: Variance documentation is initiated when the change in schedule is deemed business impactive.

Scope Variance

- ***Variance Initiation***: Variance documentation is initiated when current forecast meets variance criteria (i.e. >20% variance to budget for the number of units being completed).

AMPCO INTERROGATORY #24

Reference:

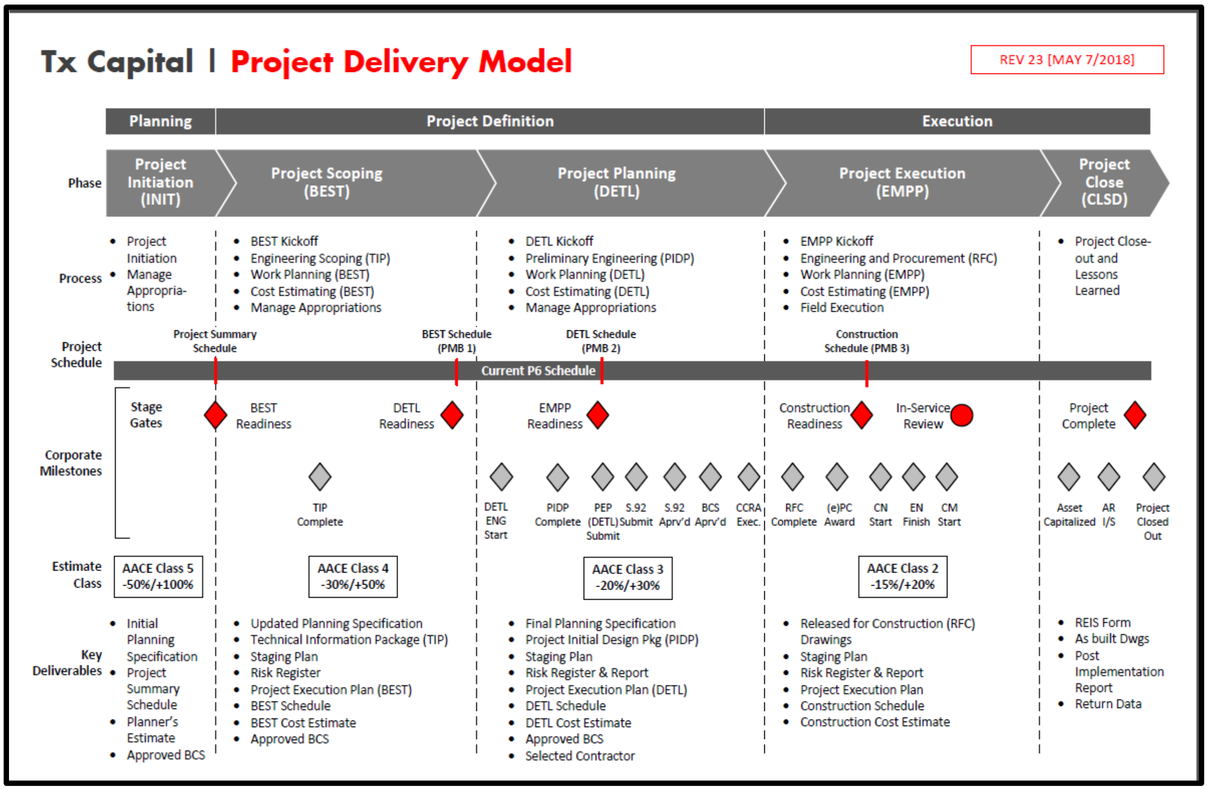
TSP-02-01 p.45

Interrogatory:

Please provide Hydro One's key internal documents that govern project management and reporting.

Response:

Hydro One manages its portfolio using typical project, program, and portfolio management methodologies and has made significant improvements in recent years. Additional information is included in the Capital Work Execution Strategy at Exhibit B, Tab 2, Schedule 1. The below Project Delivery Model illustrates a typical project lifecycle from initiation through to closure. Within these defined project phases, a governance process has been established which allows Hydro One leadership to review the project execution plan (which includes the scope, estimate, schedule, and risks) before the project is allowed to move onto the subsequent project phase. This is done to ensure that a sufficient level of project maturity is achieved before proceeding to the next phase, in turn better controlling cost & schedule



In terms of project reporting, Hydro One has a structured monthly process to review cost, schedule and scope performance for each project that is in execution. This involves monthly reviews / updates of forecasts by project managers followed by cascading reviews by the management team. The reviews by the management team include a review of overall portfolio and individual project performance for year-to-date actuals and projections, and significant project risks and issues.

AMPCO INTERROGATORY #25

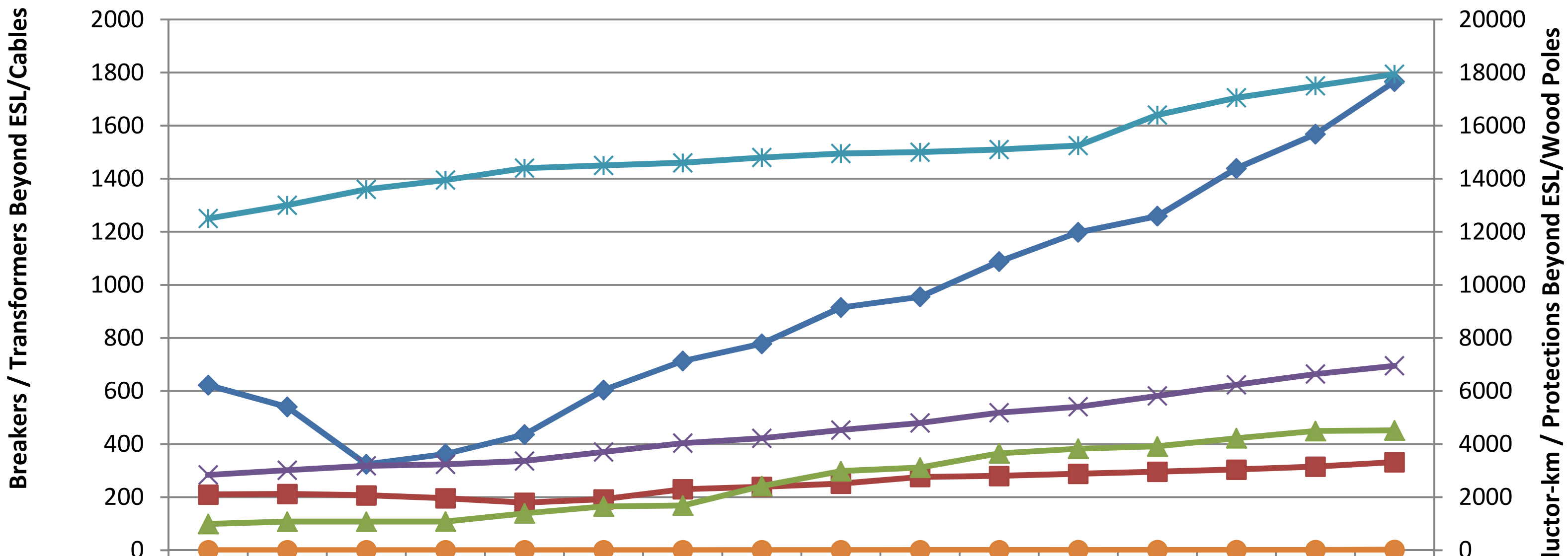
Reference:
TSP-02-02 p.2 Figure 1

Interrogatory:
Please add the years 2014 to 2018 to Figure 1 and add wood poles and underground cable to Figure 1.

Response:
Table 1 below identifies the number of assets beyond ESL per year without replacement.

Table 1 - Number of Assets beyond ESL per Year Summary

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Breakers	622	540	324	363	436	604	713	778	915	955	1088	1198	1259	1439	1568	1766
Transformers	210	212	207	196	179	192	230	239	251	276	280	288	296	304	315	332
Conductors[i]	988	1,076	1,077	1,078	1,389	1,650	1,683	2,416	2,980	3,115	3,653	3,828	3,914	4,221	4,493	4,516
Protections	2,839	3,017	3,180	3,234	3,363	3,703	4,036	4,220	4,529	4,795	5,184	5,406	5,814	6,236	6,639	6,952
Wood Poles	12,500	13,000	13,600	13,950	14,400	14,500	14,600	14,800	14,950	15,000	15,100	15,250	16,400	17,050	17,500	17,940
Cables	0	0	0	0	0	0	0	2	4	4	4	6	6	7	7	17



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Breakers	622	540	324	363	436	604	713	778	915	955	1,088	1,198	1,259	1,439	1,568	1,766
Transformers	210	212	207	196	179	192	230	239	251	276	280	288	296	304	315	332
Conductor	988	1,076	1,077	1,078	1,389	1,650	1,683	2,416	2,980	3,115	3,653	3,828	3,914	4,221	4,493	4,516
Protections	2,839	3,017	3,180	3,234	3,363	3,703	4,036	4,220	4,529	4,795	5,184	5,406	5,814	6,236	6,639	6,952
Wood Poles	12,500	13,000	13,600	13,950	14,400	14,500	14,600	14,800	14,950	15,000	15,100	15,250	16,400	17,050	17,500	17,940
Cables	0	0	0	0	0	0	0	2	4	4	4	6	6	7	7	17

Breakers Transformers Conductor Protections Wood Poles Cables

[i] The beyond ESL population for conductors in 2014 to 2017 is provided by using the present ESL of 90 years for ACSR conductors (since 2018). Prior to 2018, ACSR conductors were assigned an ESL of 70 years.

Witness: Donna Jablonsky

AMPCO INTERROGATORY #26

Reference:
TSP-02-02 p.3 Table 1

Interrogatory:

a) Please add “Population” to Table 1.

b) Please provide an excel version of Table 1.

Response:

a) Please see the table below for Hydro One’s major asset condition summary including population.

Major Asset Condition Summary

Asset Type	Very Low Risk*	Low Risk	Fair Risk	High Risk	Very High Risk*	To be Assessed	Total Population
Transformers	336	163	95	99	23	-	716
Circuit Breakers	2035	1475	804	293	167	-	4,774
Protection Systems	4,800	3,846	497	2,387	976	-	12,506
Conductors (km)	16,050		3,316	3,680		6,061	29,107
Wood Poles	-	17,640	0	5,460	-	18,900	42,000
Underground Cables (km)	-	179	77	8	-	0	264

** These categories are not used for all assets.*

b) Please refer to Attachment 1.

Major Asset Condition Summary

Asset Type	Very Low Risk*	Low Risk	Fair Risk	High Risk	Very High Risk*	To be Assessed	Total Population
Transformers	336	163	95	99	23	-	716
Circuit Breakers	2035	1475	804	293	167	-	4,774
Protection Systems	4,800	3,846	497	2,387	976	-	12,506
Conductors (km)	16,050		3,316	3,680		6,061	29,107
Wood Poles	-	17,640	0	5,460	-	18,900	42,000
Underground Cables (km)	-	179	77	8	-	0	264

** These categories are not used for all assets.*

AMPCO INTERROGATORY #27

Reference:

TSP-02-02 p.3 Table 1

Interrogatory:

Please recast Table 1 using the Major Asset Condition data from EB-2016-0160 for each asset type.

Response:

Please see the table below for Hydro One's major asset condition summary from EB-2016-0160.

Major Asset Condition Summary

Asset Type	Very Low Risk*	Low Risk	Fair Risk	High Risk	Very High Risk*	To be Assessed	Total Population
Transformers	324	224	65	94	14	-	721
Circuit Breakers	2,272	1,090	681	454	45	-	4,543
Protection Systems	4,357	3,994	484	1,936	1,331	-	12,103
Conductors (km)	11,748		5,874	2,643		9,104	29,369
Wood Poles	-	29,820	8,400	1,260	-	2,520	
Underground Cables (km)	-	195	59	11	-	3	267

** These categories are not used for all assets.*

Witness: Donna Jablonsky

AMPCO INTERROGATORY #28

Reference:

TSP-01-01

Interrogatory:

Please complete the attached excel spreadsheet B-AMPCO-28.

Response:

Please refer to Attachment 1.

Witness: Donna Jablonsky

Population	Expected Service Life	2015 # replaced beyond ESL	2016 # replaced beyond ESL	2017 # replaced beyond ESL	2018 # replaced beyond ESL	2015 # replaced in very high & high risk	2016 # replaced in very high & high risk	2017 # replaced in very high & high risk	2018 # replaced in very high & high risk	2015 # replaced beyond ESL & in very high & high risk	2016 # replaced beyond ESL & in very high & high risk	2017 # replaced beyond ESL & in very high & high risk	2018 # replaced beyond ESL & in very high & high risk
273	40-60	10	16	10	13	8	8	8	5	6	7	7	5
397	40-50	7	4	5	15	4	3	3	6	4	2	3	6
46	40	2	2	2	0	2	2	2	0	2	2	2	0
1600	55	20	13	23	58	23	13	58	63	20	13	23	58
1857	40	3	6	1	1	20	15	9	3	3	6	1	1
157	40	10	19	13	17	10	19	13	17	10	19	13	17
364	40	-	-	-	-	2	-	-	-	-	-	-	-
767	40	-	4	3	-	1	10	14	1	-	4	3	-
29	40	1	3	-	7	3	3	-	7	1	3	-	7
3484	45	66	77	54	55	66	77	54	55	66	77	54	55
1970	25	126	235	104	103	126	235	104	103	126	235	104	103
7268	20	1	7	1	5	1	7	1	5	1	7	1	5
29,107	70 (These replacements were planned before the ESL for ACSR conductors was changed from 70 to 90 years - Therefore they are based on an ESL of 70 years) See: Exhibit B-1-1, TSP Section 1.4, Attachment 4	201	183	119	51	201	183	119	51	201	183	119	51
	50 years	-	-	-	-	845	761	966	735	-	-	-	-
	80 years	-	-	-	-	-	-	-	-	-	-	-	-
	80 years	-	-	-	-	-	-	-	-	-	-	-	-
	80 years	-	-	-	-	-	-	-	-	-	-	-	-
N/A	70 years (as per for life of the line)	-	-	-	-	-	-	-	-	-	-	-	-
N/A	70 years (as per for life of the line)	-	-	-	-	155	2100	3422	3900	-	-	-	-
N/A	30 years	-	-	-	-	-	-	201	58	-	-	-	-
60 km	70 years	-	-	-	-	-	2.30	-	-	-	-	-	-
173 km	70 years	-	-	-	-	-	-	-	-	-	-	-	-
31 km	50 years	-	-	-	-	-	-	-	-	-	-	-	-

set management phylosophy. Records of the structures replacements which had passed ESL are not readily available.
m. They are coated in order to extend their life and delay high capital costs in the future

AMPCO INTERROGATORY #29

Reference:
TSP-01-01

Interrogatory:
Please provide a list of Hydro One's key transmission asset types from the highest system impact to lowest system impact upon failure.

Response:
The asset type alone does not determine the system impact upon failure. Factors such as regulatory standards (NERC, IESO), system configuration, voltage, load, number of connected customers etc, must be considered in conjunction.

During 2006 rate filing, in EB-2005-0501 Hydro One presented the concept of priority groupings for asset classes where they were deemed as Priority 1, Priority 2 or Priority 3 (see page 3 of 11 on D1-2-2 from EB-2005-0501). These priority classes are based on risk to Business Value (BV). The classes for each priority categories are shown below.

Priority 1 (P1)

Asset Class
Transformers
Gas Insulated Switchgear
Oil Circuit Breakers
Air Blast Circuit Breakers
HV/LV Switches
Operating Spares
Protection and Control
Phase Conductor
Wood Pole Structures
Underground Cables
Rights of Way
Total: 11

Priority 2 (P2)

Asset Class
High Pressure Air Systems
SF6 Circuit Breakers
Metalclad Switchgear
Power Line Carrier
High Voltage Instrument Transformers
Revenue Metering
Station Insulators
Station Cables and Potheads
Batteries and Chargers
Station Grounding Systems
Capacitor Banks
Station Buildings
Fences
Drainage and Geotechnical
Fire and Security Systems
Total: 15

Priority 3 (P3)

Asset Class
Protection System Monitoring
Station Buses
Station Surge Protection
AC/DC Service equipment
HV/LV Station Structures
Heating, ventilation and Air Conditioning
Boilers and Pressure Vessels
Oil Containment Systems
Oil and Fuel Handling Systems
Microwave Radio Systems
Fibre Optics
Metallic Cable
Site Entrance Protection Systems
Teleprotection Tone Equipment
Line Steel Structures
Line Shieldwire and Hardware
Line Insulators and Hardware
Total: 17

P1 assets represent the highest priority assets (in terms of impact on BVs) and are of high value (in terms of total sustainment program expenditures). If asset condition information is not available, unexpected failures may result in high risk to the BVs. P2 assets are second in priority with high risk to the BVs and moderate program expenditures. P3 assets are lowest in priority with low risk to the business and low program expenditures.

AMPCO INTERROGATORY #30

Reference:
TSP-01-01

Interrogatory:
Please complete the attached excel spreadsheet B-AMPCO-30.

Response:
Please refer to Attachment 1.

Witness: Donna Jablonsky

2.0-AMPCO-30
Hydro One Networks Inc. Transmission Rate Application
EB-2019-0082
Ex B TSP Section 2
5 Year Asset Failure History

TRANSMISSION ASSETS	Current Population	# Failures 2014	# Failures 2015	# Failures 2016	# Failures 2017	# Failures 2018
Transformer						
115kV	273	3	1	2	1	5
230 kV	397	1	2	2	1	3
500 kV	46	1	1	2	1	1
Circuit Breakers						
Oil	1600	2	4	6	3	1
SF 6	1857	0	0	1	1	0
Air Blast	157	0	2	1	0	0
GIS	364	0	0	0	0	0
Metaclad	767	0	0	2	0	0
Vacuum	29	0	0	0	0	0
Protection Systems						
Electromechanical	3484	23	28	22	42	38
Solid State	1970	21	17	25	25	17
Microprocessor	7268	54	78	88	99	98
Conductors	29,107	4	3	6	1	5
Poles						
Wood	42000	10	6	19	22	26
Steel Structures						
Steel Towers in Light Corrosion Zones	37300	1	1	1	2	8
Steel Towers in Heavy Corrosion Zones	13000					
Steel Poles	1950	0	0	0	0	0
Insulators						
Glass	30%	0	0	0	0	0
Poreclain	60%	4	9	4	6	6
Polymer	10%	1	2	3	2	1
Underground Cable						
LPLF	60 km	0	1	2	2	2
HPLF	173 km	0	1	2	2	2
XLPE	31 km	0	0	0	0	0

AMPCO INTERROGATORY #31

Reference:
TSP-02-02 p.13 Table 4

Interrogatory:
Please add 2018 data to Table 4.

Response:
2018 data added to Table 4:

Year	115kV	230kV	500kV	5 Year Average Annual Failure Rate, All Voltage classes
2009-2013	0.54%	0.26%	1.41%	0.44%
2014-2018	0.57%	0.56%	2.87%	0.73%
10 Year Average Annual Failure Rate	0.55%	0.41%	2.14%	0.58%

Witness: Donna Jablonsky

AMPCO INTERROGATORY #32

Reference:
TSP-02-02 p.13 Table 4

Interrogatory:
Please provide the number of transformer failures by year for the year 2008 to 2018 by 15 kV, 230 kV, and 500 kV.

Response:
Number of Transformer failures by year for the period of 2008 to 2018 by voltage class.

Year	115kV	230kV	500kV
2007	2	1	0
2008	0	4	0
2009	1	0	1
2010	1	0	1
2011	3	3	0
2012	1	0	1
2013	2	2	0
2014	3	1	1
2015	1	2	1
2016	2	2	2
2017	0	1	1
2018	2	5	1

Witness: Donna Jablonsky

AMPCO INTERROGATORY #33

Reference:
TSP-02-02

Interrogatory:
Please provide any changes to ESL by asset type compared to EB-2016-0160 and explain why.

Response:
The table below outlines assets where the ESL has been revised.

Asset	EB-2016-0160 ESL (years)	EB-2019-0082 Revised ESL (years)	Reference & Rational
Underground Cable: LPLF	50	70	Refer to Exhibit B-1-1, TSP Section 1.4.3.8
Underground Cable: HPLF	50	70	Refer to Exhibit B-1-1, TSP Section 1.4.3.8
Conductor: ACSR	70	90	Refer to Exhibit B-1-1, TSP Section 1.4.3.4

Witness: Donna Jablonsky

AMPCO INTERROGATORY #34

Reference:
TSP-02-03

Interrogatory:
Please provide any changes to Testing & Maintenance by asset type compared to EB-2016-0160 and explain why.

Response:
The maintenance strategy for Transmission assets remains the same compared to EB-2016-0160. Based on the maintenance budgetary restriction each year, maintenance was deferred accordingly as per the corresponding asset.

Witness: Donna Jablonsky

AMPCO INTERROGATORY #35

Reference:
TSP-02-03 p.57

Interrogatory:
Please provide Hydro One's Vehicle Utilization rate for the years 2015 to 2018 and provide the calculation and assumptions.

Response:
Hydro One vehicle Utilization rate from 2015 – 2018 are as follows:

2015 – $21.4
2016 – $21.3
2017 – $22.9
2018 – $24.0

This is calculated by dividing total annual fleet equipment costs by total annual fleet utilization hours. The Hydro One Utilization percentage has been approximately 80% throughout 2015 to 2018.

AMPCO INTERROGATORY #36

Reference:
TSP-03-01 Table 2, 3, and 4

Interrogatory:
Please list the ISDs that include pole replacement.

Response:
ISD SR-21

Witness: Robert Reinmuller

AMPCO INTERROGATORY #37

Issue from Draft List:
Transmission System Plan

Reference:
TSP-03-03 Tables 5,6,7 and 8

Interrogatory:
a) Please provide one excel spreadsheet for Tables 5, 6, 7 & 8.

b) Please indicate the ISDs that are new.

Response:
a) An excel version of Tables 5, 6, 7, 8 is provided as Attachment 1 to this response.

b) The following table lists the ISDs that are new since Hydro One's 2017-2018 Transmission Rate Application (EB-2016-0160).

ISD Ref	Investment Name
SA-01	Connect New IAMGOLD Mine
SA-03	Halton TS: Build a Second 230/27.6kV Station
SA-04	Connect Metrolinx Traction Substations
SA-05	Future Transmission Load Connection Plans
SR-01*	Air Blast Circuit Breaker Replacement Projects
SR-02*	Station Reinvestment Projects
SR-03	Bulk Station Transformer Replacement Projects
SR-04	Bulk Station Switchgear and Ancillary Equipment Replacement Projects
SR-05*	Load Station Transformer Replacement Projects
SR-06**	Load Station Switchgear and Ancillary Equipment Replacement Projects
SR-07	Protection and Automation Replacement Projects
SR-08	John Transformer Station Reinvestment Project
SR-12	Telecom Performance Improvements
SR-13	ADSS Fibre Optic Cable Replacements
SR-14	Mobile Radio System Replacement
SR-15	Telecom Fibre IRU Agreement Renewals
SR-19*	Transmission Line Refurbishment - End of Life ACSR Conductors & Structures
SR-20	Transmission Line Refurbishment - Near End of Life ACSR Conductor
SR-27	C5E/C7E Underground Cable Replacement
SR-28	OPGW Infrastructure Projects

ISD Ref	Investment Name
SR-29	Physical Security ISL Application Replacement
SS-01	Lennox TS: Install 500kV Shunt Reactors
SS-02	Wataynikaneyap Power Line to Pickle Lake Connection
SS-05	St. Lawrence TS: Phase Shifter Upgrade
SS-08	Northwest Bulk Transmission Line
SS-10	Kapuskasing Area Transmission Reinforcement
SS-11	South Nepean Transmission Reinforcement
SS-12	Alymer-Tillsonburg Area Transmission Reinforcement
SS-13	Leamington Area Transmission Reinforcement
SS-15	Future Transmission Regional Plans
SS-16	Customer Power Quality Program
GP-03	Network Management System Capital Sustainment
GP-04	Integrated Voice Communications and Telephony System Refresh
GP-05	Transmission Non-Operational Data Management System
GP-06	Operating Common IT Infrastructure
GP-08	Corporate Services Transformation - HR / Payroll
GP-09	Corporate Services Transformation - Finance

** Although this is a new ISD in this Application, the work proposed is the accumulation of ongoing projects from EB-2016-0160 as well newly identified projects. For a list of the new projects within the respective ISD programs, please refer to the table below.*
*** ISD SR-06 Load Station Switchgear and Ancillary Equipment Replacement consists of all new projects with the exception of the Leaside TS 26.7kV project which was listed as ISD S37 in EB-2016-0160.*

ISD Ref	Investment Name	Project Name
SR-01	Air Blast Circuit Breaker Replacement	Bruce A TS 500kV
SR-01	Air Blast Circuit Breaker Replacement	Cherrywood TS 230kV/500kV
SR-01	Air Blast Circuit Breaker Replacement	Essa TS
SR-01	Air Blast Circuit Breaker Replacement	Middleport TS
SR-01	Air Blast Circuit Breaker Replacement	Nanticoke TS
SR-02	Station Reinvestment	Runnymede TS
SR-02	Station Reinvestment	Belleville TS
SR-02	Station Reinvestment	Carlton TS
SR-02	Station Reinvestment	Port Colborne TS
SR-02	Station Reinvestment	Slater TS
SR-02	Station Reinvestment	Wonderland TS
SR-02	Station Reinvestment	Lambton TS
SR-02	Station Reinvestment	Glendale TS
SR-02	Station Reinvestment	Fairbank TS
SR-02	Station Reinvestment	Arnprior TS
SR-02	Station Reinvestment	Hanover TS
SR-02	Station Reinvestment	Kent TS
SR-02	Station Reinvestment	St. Andrews TS
SR-02	Station Reinvestment	Wawa TS
SR-05	Load Station Transformer Replacement	King Edward TS

ISD Ref	Investment Name	Project Name
SR-05	Load Station Transformer Replacement	Hanlon TS
SR-05	Load Station Transformer Replacement	Wingham TS
SR-05	Load Station Transformer Replacement	Kingsville TS
SR-05	Load Station Transformer Replacement	Thorold TS
SR-05	Load Station Transformer Replacement	Stratford TS
SR-05	Load Station Transformer Replacement	Cedar TS
SR-05	Load Station Transformer Replacement	Crowland TS
SR-05	Load Station Transformer Replacement	Murray TS
SR-05	Load Station Transformer Replacement	Orangeville TS
SR-05	Load Station Transformer Replacement	Parry Sound TS
SR-05	Load Station Transformer Replacement	Moose Lake TS
SR-05	Load Station Transformer Replacement	Lauzon TS
SR-05	Load Station Transformer Replacement	Port Hope TS
SR-05	Load Station Transformer Replacement	Longueuil TS
SR-05	Load Station Transformer Replacement	Clarke TS
SR-05	Load Station Transformer Replacement	Preston TS
SR-05	Load Station Transformer Replacement	Birmingham TS
SR-05	Load Station Transformer Replacement	Newton TS
SR-05	Load Station Transformer Replacement	Palermo TS
SR-05	Load Station Transformer Replacement	Gage TS
SR-05	Load Station Transformer Replacement	Bermondsey TS
SR-05	Load Station Transformer Replacement	Leslie TS
SR-05	Load Station Transformer Replacement	Wilson TS
SR-05	Load Station Transformer Replacement	Charles TS
SR-05	Load Station Transformer Replacement	Duplex TS
SR-05	Load Station Transformer Replacement	Woodbridge TS
SR-05	Load Station Transformer Replacement	Bathurst TS
SR-05	Load Station Transformer Replacement	Strachan TS
SR-05	Load Station Transformer Replacement	Wallace TS
SR-05	Load Station Transformer Replacement	Bilberry Creek TS
SR-05	Load Station Transformer Replacement	Russell TS
SR-05	Load Station Transformer Replacement	Elliot Lake TS
SR-05	Load Station Transformer Replacement	Fairchild TS
SR-19	Transmission Line Refurbishment - End of Life ACSR Conductors & Structures	D3A, Allanburg TS X AWS Steel CTS
SR-19	Transmission Line Refurbishment - End of Life ACSR Conductors & Structures	D6, Des Joachims JCT X Tee Lake JCT + Chalk River JCT X Petawawa JCT
SR-19	Transmission Line Refurbishment - End of Life ACSR Conductors & Structures	H1L/H3L/H6LC/H8LC, Bloor Street JCT X Leaside 34 JCT
SR-19	Transmission Line Refurbishment - End of Life ACSR Conductors & Structures	Q2AH, Rosedene JCT X St.Anns JCT
SR-19	Transmission Line Refurbishment - End of Life ACSR Conductors & Structures	Tx Line Refurb: Placeholder, Expected EOL Line Discoveries

List of Material Capital Investments (Exhibit B-1-1 TSP Section 3.3.6.1)

Table 5 - System Access - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024
SA-01	Connect New IAMGOLD Mine	24.9	0.0	0.0	0.0	0.0
SA-02	Horner TS: Build a Second 230/27.6kV Station	29.9	0.0	0.0	0.0	0.0
SA-03	Halton TS: Build a Second 230/27.6kV Station	8.0	17.7	6.0	0.0	0.0
SA-04	Connect Metrolinx Traction Substations	6.5	7.9	7.1	1.0	0.0
SA-05	Future Transmission Load Connection Plans	0.0	5.0	24.9	24.9	0.0
SA-06	Protection and Control Modifications for Distributed Generation	3.8	3.1	2.7	2.8	2.8
SA-07	Secondary Land Use Transmission Asset Modifications	55.1	15.0	13.9	15.6	3.9
	System Access Projects & Programs Less Than $3M	**27.6**	**9.4**	**8.5**	**7.8**	**9.2**
Total Gross System Access Capital ($M)		**155.7**	**58.1**	**63.0**	**52.0**	**15.8**
Less Capital Contributions ($M)		*-130.9*	*-46.7*	*-51.3*	*-39.3*	*-11.7*
Total Net System Access Capital ($M)		**24.8**	**11.3**	**11.7**	**12.7**	**4.1**

Table 6 - System Renewal - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024
SR-01	Air Blast Circuit Breaker Replacement Projects	107.5	128.4	133.5	129.2	98.7
SR-02	Station Reinvestment Projects	107.0	125.4	120.6	87.9	53.9
SR-03	Bulk Station Transformer Replacement Projects	33.2	51.8	72.5	131.5	113.8
SR-04	Bulk Station Switchgear and Ancillary Equipment Replacement Projects	17.5	32.4	41.4	34.6	49.3
SR-05	Load Station Transformer Replacement Projects	91.2	132.3	129.4	178.5	200.0
SR-06	Load Station Switchgear and Ancillary Equipment Replacement Projects	19.2	30.8	47.5	58.4	77.0
SR-07	Protection and Automation Replacement Projects	6.7	8.6	12.7	12.2	21.7
SR-08	John Transformer Station Reinvestment Project	3.5	17.9	25.6	24.0	20.9
SR-09	Transmission Station Demand and Spares and Targeted Assets	44.2	36.4	37.0	37.7	38.3
SR-10	Transformer Protection Replacement	3.8	0.0	0.0	0.0	0.0
SR-11	Legacy SONET System Replacement	4.1	26.0	27.6	28.1	28.1
SR-12	Telecom Performance Improvements	0.0	0.9	5.5	3.7	0.0
SR-13	ADSS Fibre Optic Cable Replacements	7.0	7.1	1.0	0.0	0.0
SR-14	Mobile Radio System Replacement	2.9	6.2	6.1	4.0	0.0
SR-15	Telecom Fibre IRU Agreement Renewals	0.0	2.8	8.5	2.6	1.5
SR-16	NERC CIP-014 Physical Security Implementation	18.0	18.0	18.0	0.0	0.0
SR-17	NERC CIP Transient Cyber Asset Project	3.5	0.0	0.0	0.0	0.0
SR-18	PSIT Cyber Equipment Replacement	1.0	5.0	7.7	7.0	3.4
SR-19	Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures	81.8	122.1	94.5	51.0	75.9
SR-20	Transmission Line Refurbishment - Near End of Life ACSR Conductor	62.2	63.4	111.7	117.8	137.7
SR-21	Wood Pole Structure Replacements	51.0	52.0	53.0	54.1	55.2
SR-22	Steel Structure Coating Program	11.4	21.8	22.3	22.7	23.2
SR-23	Tower Foundation Assess/Clean/Coat Program	11.8	22.3	22.8	23.3	23.7
SR-24	Transmission Line Shieldwire Replacement	12.3	12.6	12.8	13.1	13.4
SR-25	Transmission Line Insulator Replacement	68.3	69.7	66.3	67.6	68.9
SR-26	Transmission Line Emergency Restoration	9.6	9.8	10.0	10.2	10.4
SR-27	C5E/C7E Underground Cable Replacement	2.1	29.8	30.9	32.2	29.2
SR-28	OPGW Infrastructure Projects	5.3	7.5	2.2	6.2	9.7
SR-29	Physical Security ISL Application Replacement	5.0	1.1	0.0	0.0	0.0
System Renewal Projects & Programs Less Than $3M		**77.8**	**67.3**	**60.1**	**44.1**	**41.1**
Total Gross System Renewal Capital ($M)		**869.1**	**1109.2**	**1181.1**	**1181.5**	**1194.9**
Less Capital Contributions ($M)		*-3.8*	*-6.1*	*-8.3*	*-4.1*	*-1.1*
Total Net System Renewal Capital ($M)		**865.2**	**1103.1**	**1172.8**	**1177.4**	**1193.8**

List of Material Capital Investments (Exhibit B-1-1 TSP Section 3.3.6.1)

Table 7 - System Service - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024
SS-01	Lennox TS: Install 500kV Shunt Reactors	32.3	0.0	0.0	0.0	0.0
SS-02	Wataynikaneyap Line to Pickle Lake Connection	24.9	1.5	0.0	0.0	0.0
SS-03	Nanticoke TS: Connect HVDC Lake Erie Circuits	3.0	10.0	4.0	0.0	0.0
SS-04	East-West Tie Connection	46.3	38.8	22.6	0.0	0.0
SS-05	St. Lawrence TS: Phase Shifter Upgrade	9.0	18.0	9.0	0.0	0.0
SS-06	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade	5.0	10.0	8.4	0.0	0.0
SS-07	Milton SS: Station Expansion and Connect 230kV Circuits	0.0	2.0	3.0	69.4	119.1
SS-08	Northwest Bulk Transmission Line	8.0	12.9	8.9	0.0	0.0
SS-09	Barrie Area Transmission Upgrade	38.1	28.2	8.5	0.0	0.0
SS-10	Kapuskasing Area Transmission Reinforcement	6.7	3.8	0.0	0.0	0.0
SS-11	South Nepean Transmission Reinforcement	27.5	10.5	0.0	0.0	0.0
SS-12	Alymer-Tillsonburg Area Transmission Reinforcement	10.0	13.1	6.1	0.0	0.0
SS-13	Leamington Area Transmission Reinforcement	4.9	9.7	59.1	63.8	63.8
SS-14	Southwest GTA Transmission Reinforcement	10.3	7.8	6.9	3.9	2.0
SS-15	Future Transmission Regional Plans	0.0	0.0	10.5	19.6	0.0
SS-16	Customer Power Quality Program	3.3	3.4	3.4	3.4	3.5
System Service Projects & Programs Less Than $3M		**9.1**	**8.2**	**9.9**	**14.0**	**15.9**
Total Gross System Service Capital ($M)		**238.3**	**177.9**	**160.3**	**174.3**	**204.2**
Less Capital Contributions ($M)		*-34.2*	*-29.7*	*-8.5*	*0.0*	*0.0*
Total Net System Service Capital ($M)		**204.1**	**148.2**	**151.8**	**174.3**	**204.2**

Table 8 - General Plant - Material Capital Investments Proposed

ISD	Investment Name	2020	2021	2022	2023	2024
GP-01	Integrated System Operations Centre - New Facility Development	32.4	12.7	0.0	0.0	0.0
GP-02	Grid Control Network Sustainment	8.0	6.1	6.3	6.5	6.6
GP-03	Network Management System Capital Sustainment	0.0	7.8	22.4	8.2	0.0
GP-04	Integrated Voice Communications and Telephony System Refresh	0.0	1.9	3.2	1.1	0.0
GP-05	Transmission Non-Operational Data Management System	5.2	5.3	5.4	5.5	1.1
GP-06	Operating Common IT Infrastructure	0.8	2.0	3.7	3.3	2.2
GP-07	Hardware/Software Refresh and Maintenance	2.0	2.0	1.9	1.9	5.8
GP-08	Corporate Services Transformation - HR / Payroll	5.0	1.5	0.0	0.0	0.0
GP-09	Corporate Services Transformation - Finance	1.0	3.0	5.0	6.5	5.0
GP-10	Facility Accommodation & Improvements Service Centres & Admin	8.1	4.9	8.2	16.4	4.3
GP-11	Transmission Facilities & Site Improvements	9.4	9.5	9.6	9.7	9.9
GP-12	Transport & Work Equipment	13.2	13.2	13.3	13.3	13.3
General Plant Projects & Programs Less Than $3M		**30.2**	**24.3**	**15.8**	**11.1**	**10.7**
Total Gross System Service Capital ($M)		**115.4**	**94.4**	**94.7**	**83.6**	**58.9**
Total Net General Plant Capital ($M)		**115.4**	**94.4**	**94.7**	**83.6**	**58.9**

AMPCO INTERROGATORY #38

Reference:

TSP-03-03 Tables 5,6,7 and 8

Interrogatory:

a) For each of the ISDs in Tables 5, 6, 7, & 8, please provide the forecast and actual spending for the years 2015 to 2019.

b) Please provide one excel spreadsheet for part (a).

Response:

a) For each of the ISDs in Table 5, 6, 7, and 8 the approved plan and actual spending for the years 2015 to 2018 and forecast for 2019 are provided in excel format, please refer to Attachment 1 of this response.

b) Please see response to part (a).

ISD List of Material Capital Investments
(Net $ Millions)

Table 5 - System Access - Material Capital Investments Proposed

ISD	Investment Name	Actual 2015	Plan 2015	Actual 2016	Plan 2016	Actual 2017	Plan 2017	Actual 2018	Plan 2018	Forecast 2019
SA-01	Connect New IAMGOLD Mine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
SA-02	Horner TS: Build a Second 230/27.6kV Station	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	2.0
SA-03	Halton TS: Build a Second 230/27.6kV Station	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4
SA-04	Connect Metrolinx Traction Substations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
SA-05	Future Transmission Load Connection Plans	0.0	0.0	0.0	8.0	0.0	0.0	0.0	0.0	0.0
SA-06	Protection and Control Modifications for Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SA-07	Secondary Land Use Transmission Asset Modifications	0.1	0.4	1.2	0.5	(0.7)	(1.0)	4.3	5.0	2.9

Table 6 - System Renewal - Material Capital Investments

ISD	Investment Name	Actual 2015	Plan 2015	Actual 2016	Plan 2016	Actual 2017	Plan 2017	Actual 2018	Plan 2018	Forecast 2019
SR-01	Air Blast Circuit Breaker Replacement Projects	66.8	61.0	89.2	58.9	88.0	79.6	79.0	61.6	88.5
SR-02	Station Reinvestment Projects	6.7	45.7	37.8	38.6	67.6	64.4	70.0	63.1	104.8
SR-03	Bulk Station Transformer Replacement Projects	(0.2)	0.0	0.2	0.2	1.2	1.3	0.9	7.8	9.9
SR-04	Bulk Station Switchgear and Ancillary Equipment Replacement Projects	0.0	0.0	0.0	0.0	0.5	0.2	1.8	3.3	2.4
SR-05	Load Station Transformer Replacement Projects	10.1	5.0	8.8	0.9	12.2	12.0	15.0	26.8	40.3
SR-06	Load Station Switchgear and Ancillary Equipment Replacement Projects	0.3	1.9	3.7	9.7	1.6	1.7	16.0	15.7	11.7
SR-07	Protection and Automation Replacement Projects	0.0	0.0	0.0	0.0	0.2	0.2	0.4	2.5	1.9
SR-08	John Transformer Station Reinvestment Project	0.1	14.0	0.0	5.9	0.0	0.1	0.0	0.0	0.2
SR-09	Transmission Station Demand and Spares and Targeted Assets	27.0	11.1	24.2	16.4	18.5	23.6	49.6	37.1	49.7
SR-10	Transformer Protection Replacement	0.1	0.0	1.5	0.0	3.4	3.1	3.1	4.1	3.0
SR-11	Legacy SONET System Replacement	0.0	0.0	0.0	0.0	1.2	1.1	3.3	2.4	1.5
SR-12	Telecom Performance Improvements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SR-13	ADSS Fibre Optic Cable Replacements	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.4	0.5
SR-14	Mobile Radio System Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
SR-15	Telecom Fibre IRU Agreement Renewals	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SR-16	NERC CIP-014 Physical Security Implementation	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	17.9
SR-17	NERC CIP Transient Cyber Asset Project	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5
SR-18	PSIT Cyber Equipment Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	5.4
SR-19	Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures	0.2	0.0	2.1	0.0	8.1	7.8	42.7	47.0	104.6
SR-20	Transmission Line Refurbishment - Near End of Life ACSR Conductor	0.0	0.0	0.0	0.0	0.4	0.4	0.3	3.6	12.8
SR-21	Wood Pole Structure Replacements	20.8	13.8	43.8	14.1	42.7	40.3	35.3	34.9	34.8
SR-22	Steel Structure Coating Program	5.1	8.8	2.3	10.3	42.1	39.0	37.7	27.0	9.3
SR-23	Tower Foundation Assess/Clean/Coat Program	1.4	4.2	1.6	4.3	7.0	5.9	4.7	7.7	13.1
SR-24	Transmission Line Shieldwire Replacement	4.8	4.3	1.4	4.4	5.4	4.8	9.3	10.2	9.9
SR-25	Transmission Line Insulator Replacement	2.9	3.6	29.5	3.7	48.9	53.1	65.5	64.8	66.2
SR-26	Transmission Line Emergency Restoration	8.7	10.9	13.8	11.1	8.3	7.6	9.7	9.0	9.4
SR-27	C5E/C7E Underground Cable Replacement	0.0	0.0	0.0	0.0	0.5	0.3	0.5	0.6	3.2
SR-28	OPGW Infrastructure Projects	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	1.2
SR-29	Physical Security ISL Application Replacement	0.0	0.0	0.0	0.0	0.0	0.0	3.3	5.0	7.8

ISD List of Material Capital Investments
(Net $ Millions)

Table 7 - System Service - Material Capital Investments

ISD	Investment Name	Actual 2015	Plan 2015	Actual 2016	Plan 2016	Actual 2017	Plan 2017	Actual 2018	Plan 2018	Forecast 2019
SS-01	Lennox TS: Install 500kV Shunt Reactors	0.0	0.0	0.0	0.0	0.3	0.2	1.1	2.0	13.2
SS-02	Wataynikaneyap Line to Pickle Lake Connection	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	3.2
SS-03	Nanticoke TS: Connect HVDC Lake Erie Circuits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SS-04	East-West Tie Connection	0.1	0.0	1.7	0.0	4.4	4.3	8.6	10.8	31.5
SS-05	St. Lawrence TS: Phase Shifter Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
SS-06	Merivale TS to Hawthorne TS: 230kV Conductor Upgrade	0.0	0.0	0.1	0.0	0.1	0.1	0.0	0.3	0.5
SS-07	Milton SS: Station Expansion and Connect 230kV Circuits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SS-08	Northwest Bulk Transmission Line	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	5.0
SS-09	Barrie Area Transmission Upgrade	0.0	0.0	0.4	0.0	1.8	2.0	1.8	6.5	2.6
SS-10	Kapuskasing Area Transmission Reinforcement	0.0	0.0	0.1	0.0	0.7	0.7	1.7	1.5	17.5
SS-11	South Nepean Transmission Reinforcement	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.8	0.0
SS-12	Alymer-Tillsonburg Area Transmission Reinforcement	0.0	0.0	0.0	0.0	0.0	0.0	0.2	1.0	1.0
SS-13	Leamington Area Transmission Reinforcement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.9
SS-14	Southwest GTA Transmission Reinforcement	0.0	0.0	0.2	0.0	0.1	0.1	0.3	1.2	1.9
SS-15	Future Transmission Regional Plans	0.0	0.0	0.0	15.0	0.0	0.0	0.0	0.0	0.0
SS-16	Customer Power Quality Program	0.0	0.0	0.0	0.0	0.0	0.0	0.4	3.3	3.3

Table 8 - General Plant - Material Capital Investments

ISD	Investment Name	Actual 2015	Plan 2015	Actual 2016	Plan 2016	Actual 2017	Plan 2017	Actual 2018	Plan 2018	Forecast 2019
GP-01	Integrated System Operations Centre - New Facility Development	0.2	0.0	4.0	0.0	0.8	1.0	0.6	23.0	28.8
GP-02	Grid Control Network Sustainment	0.5	2.0	3.4	3.0	2.9	2.4	3.6	6.4	7.2
GP-03	Network Management System Capital Sustainment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GP-04	Integrated Voice Communications and Telephony System Refresh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GP-05	Transmission Non-Operational Data Management System	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GP-06	Operating Common IT Infrastructure	0.0	0.0	0.0	1.6	0.0	0.9	0.0	1.0	1.7
GP-07	Hardware/Software Refresh and Maintenance	5.7	4.7	8.0	4.4	6.2	6.5	4.0	7.3	3.7
GP-08	Corporate Services Transformation - HR / Payroll	0.0	0.0	0.0	0.0	0.0	0.0	0.4	2.0	0.5
GP-09	Corporate Services Transformation - Finance	0.0	0.0	0.0	0.0	0.3	0.2	0.0	0.5	0.2
GP-10	Facility Accommodation & Improvements Service Centres & Admin	0.1	0.8	6.4	0.8	5.3	7.9	4.9	19.3	7.2
GP-11	Transmission Facilities & Site Improvements	0.0	0.0	6.2	0.0	10.6	12.0	16.4	10.0	12.0
GP-12	Transport & Work Equipment	16.7	14.9	20.4	17.1	13.7	14.5	7.2	14.1	13.3

AMPCO INTERROGATORY #39

Reference:
ISD-GP-12 p.4 Table 1

Interrogatory:

a) Please provide table 1 for the years 2015 to 2019.

b) Please provide the total number of Light, Heavy and Off-road vehicles and helicopters in each of the years 2015 to 2018 an forecast for 2019 to 2022.

c) Please provide the number Light, Heavy and Off-road vehicles and helicopters replaced each year for the years 2015 to 2019 and the age at replacement.

Response:

a)

Table 1 - Forecast of Acquisitions for 2015 to 2019 (Tx Allocation) ($ millions)

Equipment Type	2015	2016	2017	2018	2019 Forecast
	Cost	Cost	Cost	Cost	Cost
Light	4.8	4.4	4	0	3.4
Heavy	8.2	10.2	4.7	5.1	3.9
Off-Road	3.4	4.2	3.4	0.8	0.5
Miscellaneous	3.6	1.6	1.3	0.4	0.9
Service Equipment	0.4	0.4	0.3	0.8	0.9
Helicopter	-	-	-	-	2
Telematics[2]	2	0.9	0.2	-	-
Total [1]	**22.4**	**21.7**	**13.9**	**7.1**	**11.6**

Light– cars, SUVs, pickups, vans

Heavy– service trucks, highway tractors, radial boom derricks (RDB), bucket trucks

Off Roads – rubber tire, tracked equipment

Miscellaneous – boats, chippers, tensioners, manlifts, forklifts

Service Equipment – snowmobiles, ATVs, managed Fleet Services.

[1]*Total investment costs are based on average unit costs and relate to approximately 400 units annually*

[2] *Telematics Spend was incurred in years 2015-2017, the table was updated to accommodate those spend*

b) Below is the total vehicle count at end of year for each year for 2015 to 2018, and Forecast for 2019 to 2022.

	Actual				Forecast			
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Light	3,062	3,136	2,700	2,676	2,635	2,635	2,635	2,635
Heavy	1,444	1,479	1,414	1,446	1,419	1,419	1,419	1,419
Off Road	482	498	476	467	459	459	459	459
Helicopters	8	8	7	7	8	8	8	8

c) Below is the count of vehicles replaced in each year, and their age at replacement.

Replacement Count	Actual				Forecast
	2015	**2016**	**2017**	**2018**	**2019**
Light	415	341	277	2	281
Heavy	70	80	40	20	53
Off Road	25	22	3	4	3
Helicopters	-	-	-	-	1

Age at Replacement	Actual				Forecast
	2015	**2016**	**2017**	**2018**	**2019**
Light	8	8	8	9	9
Heavy	13	13	12	14	13
Off Road	28	26	40	14	31
Helicopters	-	-	-	-	18

AMPCO INTERROGATORY #40

Reference:
EB-2016-0160 Exhibit J7.4

Interrogatory:
Please update the table for the years 2016 to 2018

Response:

Year	2011	2012	2013	2014	2015	2016	2017	2018
Number of momentary Interruptions	523	580	618	428	450	294	423	445
Number of sustained Interruptions	530	544	512	538	525	415	585	747
Total interruption hours	**1,873**	**1,064**	**973**	**551**	**658**	**1,209**	**637**	**1,044**

Witness: Bruno Jesus

AMPCO INTERROGATORY #41

Reference:
E-03-01 p.21

Interrogatory:
Hydro One states "The reduction in the 2017 and 2018 actual load relative to the previously approved load forecast for 2017 and 2018 is primarily driven by the impact from the expanded Industrial Conservation Initiative ("ICI") program."

Please provide further details to explain this decrease and its impact on the 2020 forecast.

Response:
As stated in the evidence at Exhibit E, Tab 3, Schedule 1 page 21, the reduction in the 2017 and 2018 actual load relative to the previously approved load forecast for 2017 and 2018 is primarily driven by the impact from the expanded ICI program. In September 2016, the Government of Ontario expanded the ICI program to include more than one thousand newly eligible Class A customers with monthly peak demand greater than 1MW, down from 3MW. Sector restrictions were also removed so that institutional and commercial businesses became eligible to participate. In April 2017, the Government of Ontario further reduced the ICI threshold from 1MW to 500kW to make Ontario consumers/market participants in targeted manufacturing and industrial sectors eligible to opt-in to the ICI. The reduction in peak demand driven by the new Class A customers participating in the ICI program were not reflected in Hydro One's approved load forecast for 2017 and 2018 in EB-2016-0160.

The 2020 Ontario Demand forecast is 3.9% lower relative to the currently approved 2018 forecast of 20,378 MW (per EB-2016-0160). The key drivers of the reduction in the 2020 load forecast are: (i) the actual load in 2017 was 3.3% lower than the forecast approved in the previous application for the year 2017, and further declined by 0.2% to 3.5% in 2018, primarily due to the expanded ICI noted above, and (ii) the load is expected to further decline by 0.4% between 2018 and 2020 due to a combination of slower economic growth and conservation initiatives during this period.

Witness: Bijan Alagheband

AMPCO INTERROGATORY #42

Reference:
F-01-01 p.3

Interrogatory:

a) Please list all planned asset management cycles with a one-time extension and the corresponding cost implications.

b) Please explain further how Hydro One proposes to manage the increase in asset risk and impact on customers

Response:

a) Below is a list of the planned asset management cycles with a one-time extension:
   - Transformer maintenance, including Oil Testing, Diagnostic Level 1 & 2, Doble Test, ULTC Maintenance
   - Breaker maintenance, including Diagnostic Testing, Selective Intrusive Inspection, Oil Breaker's Oil Analysis, Power Factor Test, Moisture Content Test
   - PCB testing and retrofill
   - Transmission Lines maintenance, including Foot Patrol, Thermovision, Conductor and Shieldwire Testing, Wood Pole Assessment, Steel Structure Assessment, Insulator Testing
   - Right of Way vegetation maintenance, including Line Clearing and Brush Control.

   The cost implication of this one-time extension is the potential increase in corrective and/or demand maintenance expenditures due to outages caused by component defects that could have been discovered sooner during these activities.

b) Hydro One manages the risk by prioritizing work programs based on impact to system reliability, safety and environment. The 2019 reduction was made on work programs that posed the lowest impact to asset risk and impact on customers.

Witness: Bruno Jesus, Donna Jablonsky

AMPCO INTERROGATORY #43

Reference:
F-01-01 p.3 Table 1

Interrogatory:
Please provide the number of FTEs at the Category Level comparing 2016, 2017, 2018 actuals to 2019 and 2020 forecast.

Response:
Hydro One does not track FTEs at the Category level. For details on FTEs, please see Exhibit I, Tab 1, Schedule OEB-195.

AMPCO INTERROGATORY #44

Reference:
F-01-01 p.5

Interrogatory:
Please provide a list of all OM&A functions that have been reallocated from 2015 to 2019 and where they have been allocated to and provide the cost impact.

Response:
As per Exhibit F-01-03 page 3, Computer Aided Design and Drafting Support function was reallocated to the Information Solutions Division since 2015. The cost impact is roughly $2M per year.

Witness: Donna Jablonsky

AMPCO INTERROGATORY #45

Reference:
F-01-01 p.7

Interrogatory:
Please explain the need for the additional governance and oversight expenditures.

Response:
Please refer to interrogatory response I-12-AMPCO-62.

Witness: Godfrey Holder

AMPCO INTERROGATORY #46

Reference:
F-01-01 p.8

Interrogatory:
Please explain the scope of the increased focus on large transmission customers.

Response:
Please refer to the response for I-01-OEB-188.

AMPCO INTERROGATORY #47

Reference:

Interrogatory:

a) With respect to corrective and preventive maintenance categories, please discuss Hydro One's priority levels for resolution.

b) Please provide the number of work requests for each of the years 2015 to 2018.

Response:

a) Hydro One's prioritization of preventive, planned corrective and unplanned corrective maintenance is based on a combination of impact to public safety, system reliability and regulatory requirements (such as FERC, NERC and NPCC).

b) The number of work requests for preventive and corrective for each of the years 2015-2018 are listed in the table below. The scope of each work request can vary significantly. Hence the numeric quantity of work requests listed below is not a good representation of the labor hour, cost or system impact.

Number of Work Request	2015	2016	2017	2018
Protection	2,630	2,443	2,316	2,889
Control	506	470	397	396
Power System Telecom	2,902	2,171	2,280	2,593
Overhead Lines	1,867	2,974	3,114	2,822
Underground Cables	857	788	705	714
Transformer	6,219	5,940	6,095	6,658
Breaker	6,782	6,439	5,881	5,046
Switches	1,976	1,867	1,886	1,789
Batteries	4,169	3,790	3,835	4,028
Total Work Request	**27,908**	**26,882**	**26,509**	**26,935**

Witness: Donna Jablonsky

AMPCO INTERROGATORY #48

Reference:
F-01-03 p.5

Interrogatory:
a) Please quantify the inspection assessment backlog.

b) Please explain the reason for the backlog.

Response:
a) Please refer to Interrogatory I-08-PWU-013.

b) Reductions to maintenance and inspection work, to manage within the OEB-approved OM&A funding enveloped resulted in fewer inspection assessments being completed

AMPCO INTERROGATORY #49

Reference:
F-01-03 p.5 and 48

Interrogatory:
Please provide a copy of NERC FAC-0003 (Transmission Vegetation Management)

Response:
The latest standard of NERC FAC-003-4, Transmission Vegetation Management, can be found in Attachment 1.

Witness: Donna Jablonsky

A. Introduction

1. **Title:** **Transmission Vegetation Management**

2. **Number:** **FAC-003-4**

3. **Purpose:** **To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.**

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Applicable Transmission Owners

4.1.1.1. Transmission Owners that own Transmission Facilities defined in 4.2.

4.1.2. Applicable Generator Owners

4.1.2.1. Generator Owners that own generation Facilities defined in 4.3.

4.2. Transmission Facilities: Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1. Each overhead transmission line operated at 200kV or higher.

4.2.2. Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

4.2.4. Each overhead transmission line identified above (4.2.1. through 4.2.3.) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

4.3. Generation Facilities: Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities:

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[1] EPAct 2005 section 1211c: *“Access approvals by Federal agencies.”*

[2] *Id.*

4.3.1. Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner's Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1. Operated at 200kV or higher; or

4.3.1.2. Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or

4.3.1.3. Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

5. Effective Date: See Implementation Plan

6. Background: This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system* *<u>performance result or outcome</u>?*

b) Risk-based preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that* *<u>reduces a stated risk</u>* *to the reliability of the bulk power system?*

c) Competency-based defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have* *<u>what capability</u>, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

[3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[4] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

[4] This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

1.1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[5]

1.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[6]

1.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[7],

1.4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[8]

M1. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[9] *[Violation Risk Factor: High] [Time Horizon: Real-time]*:

2.1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[10]

2.2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[11]

2.3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[12]

2.4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage.[13]

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[5] If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.
[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.
[7] *Id.*
[8] *Id.*
[9] See footnote 4.
[10] See footnote 5.
[11] See footnote 6.
[12] *Id.*

[13] *Id.*

M2. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following: *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]:*

3.1. Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2. Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time].*

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When an applicable Transmission Owner and an applicable Generator Owner are constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[14] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.). Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

7.1. Change in expected growth rate/environmental factors

7.2. Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner[15]

7.3. Rescheduling work between growing seasons

7.4. Crew or contractor availability/Mutual assistance agreements

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[14] When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

[15] Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

7.5. Identified unanticipated high priority work

7.6. Weather conditions/Accessibility

7.7. Permitting delays

7.8. Land ownership changes/Change in land use by the landowner

7.9. Emerging technologies

M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, for three calendar years.
- The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- If an applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

1.4. Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

  A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW;

- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

  The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Violation Severity Levels (Table 1)

R #	Table 1: Violation Severity Levels (VSL)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R2.			The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of	The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of

			an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-4-Table 2 was observed in real time absent a Sustained Outage.	an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • *A fall-in from inside the active transmission line ROW* • *Blowing together of applicable lines and vegetation located inside the active transmission line ROW* • *A grow-in*
R3.		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity's applicable lines. (Requirement R3, Part 3.2.)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity's applicable lines. (Requirement R3, Part 3.1.)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity's applicable lines.
R4.			The responsible entity experienced a confirmed	The responsible entity experienced a confirmed

			vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5.				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6.	The responsible entity failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The responsible entity failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The responsible entity failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7.	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Variances

None.

E. Associated Documents

- FAC-003-4 Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	January 20, 2006	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	New
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	New
2	March 21, 2013	FERC Order issued approving FAC-003-2 (Order No. 777) FERC Order No. 777 was issued on March 21, 2013 directing NERC to "conduct or contract testing to obtain empirical data and submit a report to the Commission providing the results of the testing."[16]	Revisions

[16] *Revisions to Reliability Standard for Transmission Vegetation Management, Order No. 777,* 142 FERC ¶ 61,208 (2013)

2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from "Medium" to "High."	Revisions
3	May 9, 2013	FAC-003-3 adopted by Board of Trustees	Revisions
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard became enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 became enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) became enforceable on January 1, 2016.	Revisions
3	November 22, 2013	Updated the VRF for R2 from "Medium" to "High" per a Final Rule issued by FERC	Revisions
3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	Revisions
4	February 11, 2016	Adopted by Board of Trustees. Adjusted MVCD values in Table 2 for alternating current systems, consistent with findings reported in report filed on August 12, 2015 in Docket No. RM12-4-002 consistent with FERC's directive in Order No. 777, and based on empirical testing results for flashover distances between conductors and vegetation.	Revisions
4	March 9, 2016	Corrected subpart 7.10 to M7, corrected value of .07 to .7	Errata
4	April 26, 2016	FERC Letter Order approving FAC-003-4. Docket No. RD16-4-000.	

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[17]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)+	(AC) Maximum System Voltage (kV)[18]	MVCD (feet) Over sea level up to 500 ft	MVCD feet Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft	MVCD feet Over 11000 ft up to 12000 ft	MVCD feet Over 12000 ft up to 13000 ft	MVCD feet Over 13000 ft up to 14000 ft	MVCD feet Over 14000 ft up to 15000 ft
765	800	11.6ft	11.7ft	11.9ft	12.1ft	12.2ft	12.4ft	12.6ft	12.8ft	13.0ft	13.1ft	13.3ft	13.5ft	13.7ft	13.9ft	14.1ft	14.3ft
500	550	7.0ft	7.1ft	7.2ft	7.4ft	7.5ft	7.6ft	7.8ft	7.9ft	8.1ft	8.2ft	8.3ft	8.5ft	8.6ft	8.8ft	8.9ft	9.1ft
345	362[19]	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft
287	302	5.2ft	5.3ft	5.4ft	5.5ft	5.6ft	5.7ft	5.8ft	5.9ft	6.1ft	6.2ft	6.3ft	6.4ft	6.5ft	6.6ft	6.8ft	6.9ft
230	242	4.0ft	4.1ft	4.2ft	4.3ft	4.3ft	4.4ft	4.5ft	4.6ft	4.7ft	4.8ft	4.9ft	5.0ft	5.1ft	5.2ft	5.3ft	5.4ft
161*	169	2.7ft	2.7ft	2.8ft	2.9ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft	3.3ft	3.3ft	3.4ft	3.5ft	3.6ft	3.7ft	3.8ft
138*	145	2.3ft	2.3ft	2.4ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft	2.7ft	2.8ft	2.8ft	2.9ft	3.0ft	3.0ft	3.1ft	3.2ft
115*	121	1.9ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.1ft	2.2ft	2.2ft	2.3ft	2.3ft	2.4ft	2.5ft	2.5ft	2.6ft	2.7ft
88*	100	1.5ft	1.5ft	1.6ft	1.6ft	1.7ft	1.7ft	1.8ft	1.8ft	1.8ft	1.9ft	1.9ft	2.0ft	2.0ft	2.1ft	2.2ft	2.2ft
69*	72	1.1ft	1.1ft	1.1ft	1.2ft	1.2ft	1.2ft	1.2ft	1.3ft	1.3ft	1.3ft	1.4ft	1.4ft	1.4ft	1.5ft	1.6ft	1.6ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

+ *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

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[17] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[18] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[19] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the Supplemental Materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[20]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)[+]	(AC) Maximum System Voltage (kV)[21]	MVCD meters Over sea level up to 153 m	MVCD meters Over 153m up to 305m	MVCD meters Over 305m up to 610m	MVCD meters Over 610m up to 915m	MVCD meters Over 915m up to 1220m	MVCD meters Over 1220m up to 1524m	MVCD meters Over 1524m up to 1829m	MVCD meters Over 1829m up to 2134m	MVCD meters Over 2134m up to 2439m	MVCD meters Over 2439m up to 2744m	MVCD meters Over 2744m up to 3048m	MVCD meters Over 3048m up to 3353m	MVCD meters Over 3353m up to 3657m	MVCD meters Over 3657m up to 3962m	MVCD meters Over 3962 m up to 4268 m	MVCD meters Over 4268m up to 4572m
765	800	3.6m	3.6m	3.6m	3.7m	3.7m	3.8m	3.8m	3.9m	4.0m	4.0m	4.1m	4.1m	4.2m	4.2m	4.3m	4.4m
500	550	2.1m	2.2m	2.2m	2.3m	2.3m	2.3m	2.4m	2.4m	2.5m	2..5m	2.5m	2.6m	2.6m	2.7m	2.7m	2.7m
345	362[22]	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m	1.7m	1.7m	1.8m
287	302	1.6m	1.6m	1.7m	1.7m	1.7m	1.7m	1.8m	1.8m	1.9m	1.9m	1.9m	2.0m	2.0m	2.0m	2.1m	2.1m
230	242	1.2m	1.3m	1.3m	1.3m	1.3m	1.3m	1.4m	1.4m	1.4m	1.5m	1.5m	1.5m	1.6m	1.6m	1.6m	1.6m
161*	169	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m	1.0m	1.0m	1.0m	1.1m	1.1m	1.1m	1.1m
138*	145	0.7m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.9m	0.9m	0.9m	0.9m	0.9m	1.0m	1.0m
115*	121	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m	0.7m	0.7m	0.7m	0.8m	0.8m	0.8m	0.8m
88*	100	0.4m	0.4m	0.5m	0.5m	0.5m	0.5m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.6m	0.7m	0.7m
69*	72	0.3m	0.3m	0.3m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.4m	0.5m	0.5m	0.5m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[+] *Table 2 – Table of MVCD values at a 1.0 gap factor (in U.S. customary units), which is located in the EPRI report filed with FERC on August 12, 2015. (The 14000-15000 foot values were subsequently provided by EPRI in an updated Table 2 on December 1, 2015, filed with the FAC-003-4 Petition at FERC)*

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[20] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[21] Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

[22] The change in transient overvoltage factors in the calculations are the driver in the decrease in MVCDs for voltages of 345 kV and above. Refer to pp.29-31 in the supplemental materials for additional information.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[23]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

[23] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Guideline and Technical Basis

Effective dates:

The Compliance section is standard language used in most NERC standards to cover the general effective date and covers the vast majority of situations. A special case covers effective dates for (1) lines initially becoming subject to the Standard, (2) lines changing in applicability within the standard.

The special case is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2015 may identify a line to have that designation beginning in PY 2025, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. A line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The later of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the current definition to allow the use of such vegetation widths if there were no engineering or construction standards that

referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspection:
The current glossary definition of this NERC term was modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the derivation of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet equation. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 of the Standard provides MVCD values for various voltages and altitudes. The table is based on empirical testing data from EPRI as requested by FERC in Order No. 777.

Project 2010-07.1 Adjusted MVCDs per EPRI Testing:
In Order No. 777, FERC directed NERC to undertake testing to gather empirical data validating the appropriate gap factor used in the Gallet equation to calculate MVCDs, specifically the gap factor for the flash-over distances between conductors and vegetation. See, Order No. 777, at P 60. NERC engaged industry through a collaborative research project and contracted EPRI to complete the scope of work. In January 2014, NERC formed an advisory group to assist with developing the scope of work for the project. This team provided subject matter expertise for developing the test plan, monitoring testing, and vetting the analysis and conclusions to be submitted in a final report. The advisory team was comprised of NERC staff, arborists, and industry members with wide-ranging expertise in transmission engineering, insulation coordination, and vegetation management. The testing project commenced in April 2014 and continued through October 2014 with the final set of testing completed in May 2015. Based on these testing results conducted by EPRI, and consistent with the report filed in FERC Docket No. RM12-4-000, the gap factor used in the Gallet equation required adjustment from 1.3 to 1.0. This resulted in increased MVCD values for all alternating current system voltages identified. The adjusted MVCD values, reflecting the 1.0 gap factor, are included in Table 2 of version 4 of FAC-003.

The air gap testing completed by EPRI per FERC Order No. 777 established that trees with large spreading canopies growing directly below energized high voltage conductors create the greatest likelihood of an air gap flash over incident and was a key driver in changing the gap factor to a more conservative value of 1.0 in version 4 of this standard.

Requirements R1 and R2:
R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations. These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:
R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated*

2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

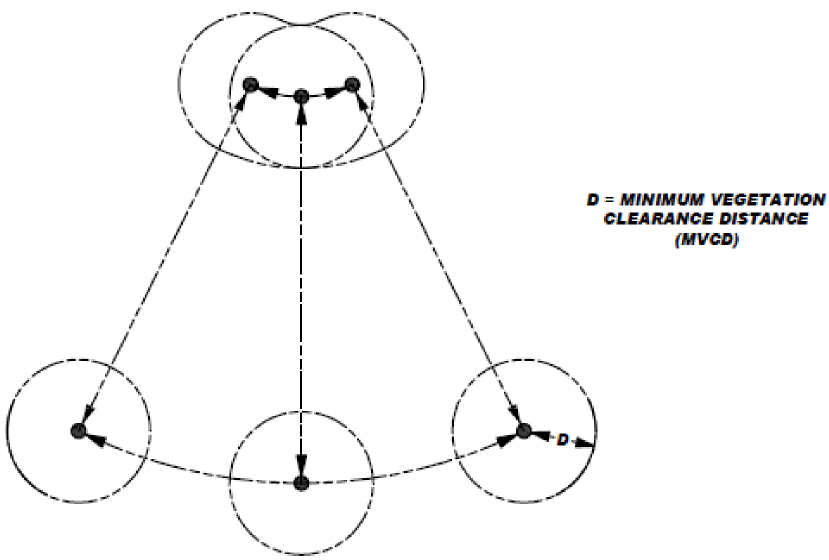


Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of herbicides to control incompatible vegetation outside of the MVCD, but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable

Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

When an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner's or applicable Generator Owner's annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If an applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner's or applicable Generator Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.
In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner's or applicable Generator Owner's easement, fee simple and

other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 used the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-1 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is in service from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line was approximately 2.0 per unit. This value was a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below was considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit was considered a realistic maximum.

The Gallet equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet "wet" formulas are not vastly different when the same transient overvoltage factors are used; the "wet" equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

Since no empirical data for spark over distances to live vegetation existed at the time version 3 was developed, the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs.

IEEE 516-2003 MAID distances

(AC) **Nom System** **Voltage (kV)**	**(AC)** **Max System** **Voltage (kV)**	**Transient** **Over-voltage** **Factor (T)**	**Clearance (ft.)** **Gallet (wet)** **@ Alt. 3000 feet**	Table 7 (Table D.5 for feet) **IEEE 516-2003** **MAID (ft)** **@ Alt. 3000 feet**
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.
Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows:

1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event.
2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment.
3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):
Within the text of NERC Reliability Standard FAC-003-3, "transmission line(s)" and "applicable line(s)" can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1 and R2:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the

applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions.

Rationale for R4:

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

AMPCO INTERROGATORY #50

Reference:
F-01-03 p.5 and 48

Interrogatory:
a) Please provide the number of trees managed by Hydro One.

b) Please provide the number of damage trees removed for each of the years 2014 to 2018 and forecast for 2019 and 2020.

Response:
a) Hydro One does not count the total number of trees managed by its transmission vegetation management program. However, Hydro One does track the progress of its transmission vegetation work program using units of hectares and kilometers. Please refer to Exhibit B-1-1, TSP Section 1.5, pages 43-47 for Hydro One's historical costs and accomplishments.

b) Hydro One does not track the number of danger trees removed annually as part of vegetation maintenance.

AMPCO INTERROGATORY #51

Reference:
F-01-03 p.5 and 50

Interrogatory:
Please provide the unit accomplishments for Demand Control for each the years 2014 to 2018 and the forecast for 2019 and 2020.

Response:
Due to the varying scope of work associated with each unplanned maintenance activity, accomplishments for the Demand Maintenance program are tracked in terms of dollars spent rather than units completed. Please refer to the table below for historical actual and forecast costs for the Demand Maintenance program.

Vegetation Management OM&A ($ Millions)

Description	Historical Years				Bridge Year	Test Year
	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Forecast
Demand Maintenance	1.5	1.3	1.3	2.0	1.3	1.4

Witness: Donna Jablonsky

AMPCO INTERROGATORY #52

Reference:

F-01-03 p.5 and 48

Interrogatory:

Please provide the forecast and actual unit accomplishments for Brush Control for each the years 2014 to 2018 and the forecast for 2019 and 2010.

Response:

The planned and actual unit accomplishments for Brush Control are listed in the table below:

Forecast and Actual Brush Control Unit Accomplishments (Ha)

Activity	Historical Years										Bridge Year	Test Year
	2014	2014	2015	2015	2016	2016	2017	2017	2018	2018	2019	2020
	Planned	Actual	Planned	Actual	Planned	Actual	Planned	Actual	Planned	Actual	Forecast	Forecast
Brush Control	13,000	12,625	11,100	11,356	12,500	12,144	11,500	12,040	12,500	12,850	10,794	11,200

The 2019 and 2020 forecast unit accomplishments for the Brush Control program are less than the historical average due to the reprioritization and deferral of certain work programs within the 2019 OM&A envelope (2019) and an increase in the Brush Control unit cost (2019 and 2020). The increase in the Brush Control unit cost is due to the greater amount of labour required to treat overgrowth on right-of-ways where maintenance has been deferred and to perform public consultations in advance of urban vegetation management.

Witness: Donna Jablonsky

AMPCO INTERROGATORY #53

Reference:

F-01-03 p.5 and 58

Interrogatory:

Please provide the forecast and actual unit accomplishments for Line Clearing for each of the years 2014 to 2018 and the forecast for 2019 and 2010.

Response:

The forecast and actual unit accomplishments for Line Clearing are listed in the table below:

Forecast and Actual Line Clearing Unit Accomplishments

Activity	Historical Years										Bridge Year	Test Year
	2014	2014	2015	2015	2016	2016	2017	2017	2018	2018	2019	2020
	Planned	Actual	Planned	Actual	Planned	Actual	Planned	Actual	Planned	Actual	Forecast	Forecast
Line Clearing	3,400	3,287	2,300	3,735	3,100	3,122	2,800	2,805	3,000	3,049	2,019	2,858

The 2019 forecast unit accomplishments for the Line Clearing program are less than the historical average due to the reprioritization and deferral of certain work programs within the 2019 OM&A envelope, and an increase in the Line Clearing unit cost. The increase in Line Clearing unit cost is due to the greater amount of labour required to clear right-of-ways to design width and to perform vegetation management in urban areas.

Witness: Donna Jablonsky

AMPCO INTERROGATORY #54

Reference:
F-01-03 p.5 and 48

Interrogatory:
Please provide the percentage and value of the OM&A budget that is undertaken by external resources for the years 2014 to 2018 and forecast for 2019 and 2020.

Response:
Hydro One completes all transmission vegetation management forestry work internally with one exception related to brush clearing work on right-of-ways located on Indigenous land. In these cases, completion of brush removal work is offered to the local Indigenous Community. This work amounts to less than 1 percent of Hydro One's annual vegetation management forestry budget. Please refer to the table below for the percentage and value of the Vegetation Management Forestry OM&A budget that is undertaken by Indigenous Communities.

Vegetation Management Forestry OM&A ($ millions)

	Actual Cost					Forecast Cost	
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Vegetation Management Forestry Work[1]	33.0	31.1	29.5	27.3	35.5	28.0	29.9
Percent of Vegetation Management Forestry Work Completed by Indigenous Communities	<1%	<1%	<1%	<1%	<1%	<1%	<1%

As stated in Exhibit B-1-1, TSP Section 2.3, p. 47, Hydro One also performs grounds maintenance to cut grass, remove snow, clean-up garbage and repair access barriers and fences along Hydro One's urban right-of-ways. This maintenance is required to comply with local by-laws and has been completed by BGIS since January 1st, 2015. Please refer to interrogatory response I-10-VECC-041 for a breakdown of the BGIS costs for 2018. Please refer to the table below for the percentage and value of the Grounds Maintenance OM&A budget that is undertaken by external resources.

Vegetation Management OM&A ($ millions)

	Actual Cost					Forecast Cost	
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Grounds Maintenance Work	2.5	1.5	1.7	2.1	1.9	1.7	2.0
Percent of Grounds Maintenance Work Completed by BGIS	0%	100%	100%	100%	100%	100%	100%

AMPCO INTERROGATORY #55

Reference:
F-01-03 p.5 and 48

Interrogatory:
Please provide the number of cable locates for the years 2014 to 2018 and the forecast for 2019 and 2020.

Response:
The table below outlines the actual number of locate requests received by Hydro One Transmission between 2014 and 2018 and forecasts for 2019 and 2020.

Year	Number of Locates
2014	19,922
2015	20,167
2016	19,739
2017	20,781
2018	13,140
2019	14,000
2020	14,000

Cable locates are driven by external demand and are primarily dependent on the number of infrastructure projects in the GTA, Hamilton and Ottawa. In 2018 Ontario One Call updated their mapping system (improving accuracy) and changed their process resulting in fewer locate requests being sent to Hydro One (where no cables were present).

Witness: Donna Jablonsky

AMPCO INTERROGATORY #56

Reference:
F-01-03

Interrogatory:
a) Please provide a table that combines Table 1 to Table 15.

b) Please provide an excel version of the Table.

Response:
a) and b) please refer to Attachment 1.

Witness: Donna Jablonsky

	Description	Historical								Bridge	Test
		2015		2016		2017		2018		2019	2020
		Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Forecast	Forecast
Summary of Sustainment OM&A ($ Millions)	Stations	175	169	159.3	171.6	162.7	178.5	161.4	174.8	145.7	155.4
	Lines	52.6	57.8	51.4	58.8	51.5	59.8	63.8	60.8	47.7	53.4
	Engineering and Environmental Support	6	11.9	4.4	10.8	4	2.9	4.1	2.9	7.2	5.3
	Total Sustainment	**233.6**	**238.7**	**215.1**	**241.1**	**218.1**	**241.2**	**229.4**	**238.5**	**200.6**	**214.2**
	Description	**Historical Years**								**Bridge Year**	**Test Year**
		2015		**2016**		**2017**		**2018**		**2019**	**2020**
		Actual		**Actual**		**Actual**		**Actual**		**Forecast**	**Forecast**
Stations Sustainment OM&A ($ Millions)	Land Assessment and Remediation	3.6		2.9		1.8		1.3		1	1.5
	Environmental Management	9.8		9.3		16.7		13.9		14.8	22.1
	Power Equipment Maintenance	64.5		55.3		56.5		60.1		47.1	50.7
	Ancillary Systems Maintenance	9.2		9.2		8.5		8.3		8.6	8.8
	Protection, Automation and Telecom Maintenance	42.7		40.8		41.6		40.6		39	35.4
	Site Infrastructure Maintenance	24		22.6		22.6		22.7		19.9	21.3
	Cyber Security Management	21.2		19.2		14.9		14.6		15.3	15.6
	Total	**175**		**159.3**		**162.7**		**161.4**		**145.7**	**155.4**
Environmental Management OM&A ($ Millions)	PCB Retirement and Waste Management	5.3		4.3		7.4		6.9		7.7	14.6
	Transformer Oil Leak Reduction	0.9		2.3		4.1		3		2.5	2.5
	Preventive and Corrective Maintenance	2.7		1.8		3.4		2.6		1.7	1.7
	Environmental Compliance and Emergency Response Plan Updates	1		0.9		1.8		1.4		2.9	3.3
	Total	**9.8**		**9.3**		**16.7**		**13.9**		**14.8**	**22.1**
Power Equipment Maintenance OM&A ($ Millions)	Preventive Maintenance	21.1		21.1		20.6		19.4		15.2	17.6
	Corrective Maintenance	28.7		23.6		25.4		30		24.1	24.5
	500kV Autotransformer Refurbishments	2		1.1		1.7		0		0	0
	Transformer Refurbishments	5.8		3.6		4.4		4.9		2.4	3.9
	Breaker Refurbishment	3.6		2.8		1.7		3.9		2.6	2.6
	Other Maintenance and Inspection Programs	3.4		2.9		2.7		1.9		2.8	2.1
	Total	**64.5**		**55.2**		**56.5**		**60.1**		**47.1**	**50.7**
Ancillary Systems Maintenance OM&A ($ Millions)	Preventive Maintenance	4.4		4.6		4.3		4.1		4.1	4
	Corrective Maintenance	3.6		3.5		3.3		3.6		3.1	3.1
	Other Maintenance Programs	1.2		1.2		0.9		0.6		1.3	1.7
	Total	**9.2**		**9.2**		**8.5**		**8.3**		**8.6**	**8.8**
Protection, Automation and Telecom OM&A ($ Millions)	Protection and Automation	19.6		17.7		18		16.4		15.9	14
	Telecom	23.1		23		23.5		24.2		22.9	21.5
	Total	**42.7**		**40.7**		**41.5**		**40.6**		**38.8**	**35.5**
Protection and Automation OM&A ($ Millions)	Preventive Maintenance	3.3		2.6		3.2		2.7		3.6	3.8
	Corrective Maintenance	7.6		6.2		6.9		7.2		6.3	6.9
	Support Processes and Systems	8.7		8.9		7.9		6.6		6	3.3
	Total	**19.6**		**17.7**		**18**		**16.4**		**15.9**	**14**
Power System Telecom OM&A ($ Millions)	Preventive and Corrective Maintenance	5.1		3.4		3.8		4.3		4.7	4.4
	Leased Telecommunication Circuits for Power System	9.1		10.4		10.4		10.5		10.8	11
	Operation of Power System Telecom Services	8.9		9.3		9.2		9.4		7.4	6.1
	Total	**23.1**		**23**		**23.5**		**24.2**		**22.9**	**21.5**
Site Infrastructure Maintenance OM&A ($ Millions)	Facilities/ Infrastructure Maintenance	21.6		20.4		20.4		20.5		17.9	19.4
	Grounds Maintenance	0.7		0.7		0.7		0.6		0.5	0.5
	Site Perimeter Maintenance	1.7		1.4		1.5		1.6		1.4	1.4
	Total	**24**		**22.6**		**22.6**		**22.7**		**19.8**	**21.3**
Cyber Security OM&A ($ Millions)	Cyber Security Maintenance and Support	11.1		8.6		10.8		9.8		10.5	11.7
	Cyber Security Vulnerability Assessment and Audit	0.1		0.4		1.7		0.6		0.4	0.5
	Special Compliance Related Projects	10		10.3		2.4		4.2		4.4	3.4
	Total	**21.2**		**19.2**		**14.9**		**14.6**		**15.3**	**15.6**

Lines Sustainment OM&A ($ Millions)	Vegetation Management	32.6		31.2		29.4		37.3		29.7	31.9
	Overhead Lines Maintenance	15.9		16.4		17.3		18.9		14	17.2
	Underground Cable Maintenance	4.1		3.8		4.8		7.6		4.1	4.4
	Total	**52.6**		**51.4**		**51.5**		**63.8**		**47.7**	**53.4**
Vegetation Management OM&A ($ Millions)	Brush Control	17.8		18.7		16.3		20.1		17.4	18.5
	Line Clearing	8.4		6.2		5.9		8.7		6.2	6.6
	Condition Patrol	1.7		1.6		1.7		1.3		1.3	1.4
	Property Owner Notifications	1.4		1.3		1.6		2.4		1.4	1.6
	Annual Vegetation Patrol	0.3		0.4		0.5		1		0.4	0.4
	Demand Maintenance	1.5		1.3		1.3		2		1.3	1.4
	Grounds Maintenance	1.5		1.7		2.1		1.9		1.7	2
	Total	**32.6**		**31.2**		**29.4**		**37.3**		**29.7**	**31.9**
Overhead Lines Maintenance OM&A ($ Millions)	Preventive Maintenance and Asset Assessment	6.5		8.4		9.2		8		6.9	9.2
	Demand Maintenance	3.9		3.5		4.6		8.5		4	4.2
	Planned Corrective Maintenance and Projects	5.4		4.6		3.6		2.4		3.1	3.7
	Total	**15.9**		**16.4**		**17.3**		**18.9**		**14**	**17.2**
Underground Cable Maintenance OM&A ($ Millions)	Preventive Maintenance	0.8		0.9		0.9		0.8		1	1
	Corrective Maintenance	2.1		1.6		2.4		5.7		1.5	1.8
	Cable Locates	1.2		1.3		1.6		1.1		1.5	1.6
	Total	**4.1**		**3.8**		**4.8**		**7.6**		**4**	**4.4**
Engineering and Environmental Support OM&A	Engineering and Environmental Support	6		4.4		4		4.1		7.2	5.3
	Total	**6**		**4.4**		**4**		**4.1**		**7.2**	**5.3**

AMPCO INTERROGATORY #57

Reference:
F-01-04 p.3

Interrogatory:
Please provide the smart grid coverage of Hydro One's system as a percentage.

Response:
Generally the term "smart grid" refers to the increased use of digital information, communication and controls technology to improve visibility and remote control of the grid, with a general association with distribution systems.

With respect to Hydro One Transmission, its transmission system has the essential features of a "smart" system as it utilizes protection, communication and control to operate its entire transmission system from a centrally located control center.

Witness: Robert Reinmuller

AMPCO INTERROGATORY #58

Reference:
F-01-04 p.5

Interrogatory:
Please estimate the cost impact in 2020 of implementing the proposed revisions to 8 functional requirement standards and 74 engineering design and constructions standards.

Response:
The estimated cost in 2020 of developing and revising approximately 8 functional requirement standards and 74 engineering, design and constructions standards is approximately $2.8 million.

Witness: Robert Reinmuller

AMPCO INTERROGATORY #59

Reference:

F-01-04 p.7

Interrogatory:

Please provide the spending on Emerging Technology for the years 2015 to 2019 and the forecast for 2020.

Response:

Spending on emerging technologies over the 2015 to 2020 period is as follows:

$ millions	2015	2016	2017	2018	2019 Forecast	2020 Forecast
Emerging Technology	0.3	0.2	0.2	0.3	0.2	0.2

Witness: Robert Reinmuller

AMPCO INTERROGATORY #60

Reference:
F-01-04 p.8

Interrogatory:

a) Please provide the objectives of the Customer PQ program.

b) Please provide the number of customer enrollments in Customer PQ meter integration program compared to the 2020 forecast.

c) Please explain scope of the third party PQ audit activities.

Response:

a) The objectives of the customer PQ program are as follows:
   - improve PQ performance visibility in the network;
   - reduce PQ disturbances resulting from capacitor bank switching; and
   - provide third party PQ Audit of industrial/commercial customers' facilities.

b) Customer enrollment is as follows:

Period	Number of Customers
Currently enrolled	23
Forecast enrollment 2020	10 to 12

c) The third party PQ Audit of a customer facility begins with a preliminary high-level review to identify key equipment and processes essential to the reliable operation of a plant or facility. This is followed by an in-plant visit to gather technical details down to an individual component level for key equipment, controls, and interfaces. The gathered information is then analyzed off-site, to identify particular PQ vulnerabilities needing mitigation. Targeted recommendations are developed involving options such as: configuration changes, reprogramming controller settings, or interchanging existing components with available commercial alternatives. Findings include forecasts of expected performance improvements and approximate implementation costs.

Witness: Robert Reinmuller

AMPCO INTERROGATORY #61

Reference:
F-01-05 p.3

Interrogatory:
With respect to Operations staff labour costs, please provide the forecast and actual average vacancy rate applied for the years 2015 to 2018 and the forecast for 2019 and 2020.

Response:
Please refer to interrogatory response I-07-SEC-051 for the actual and forecast vacancy rates for all groups.

AMPCO INTERROGATORY #62

Reference:
F-01-05 p.3

Interrogatory:
Please explain the need for additional governance and oversight expenditures in in 2016.

Response:
2016 was a ramp-up year and included one-time transition costs to achieve better organizational alignment.

AMPCO INTERROGATORY #63

Reference:

F-01-05 p.4

Interrogatory:

Please provide the number of planned outages compared to actual outages for the years 2015 to 2018 and the forecast for 2019 and 2020.

Response:

	Planned Outages (Tx)*	**Actual Outages (Tx)****
2015	12,563	11,117
2016	12,083	10,343
2017	12,615	11,170
2018	12,429	11,339
2019 (Forecast)	Hydro One does not produce forecasts for planned outages.	
2020 (Forecast)		

***Total number of outage requests by for outage types: PO (Planned Outage), POFE (Planned Outage Forced Extension), PSN (Planned Short Notice) and CA-SN (Controlling Authority – Short Notice).*

**** Planned Outages completed/executed.*

Witness: Godfrey Holder

AMPCO INTERROGATORY #64

Reference:
F-01-06 p.2 Table 1

Interrogatory:
Please explain further the scope of the $3.4 million increase in spending primarily due to an increased focus on large transmission customers.

Response:
The $3.4 million increase in spending from 2018 “Plan” to 2019 “Forecast” is related to organizational changes and realignment in order to transition to functional and geographic groups as well as to dedicate more resources to transmission customers. The cost increase is offset by a cost decrease in Corporate Affairs from 2018 “Plan” to 2019 “Forecast” of $3.1M, as evidenced in F-01-06 p.2 Table 2.

Witness: Spencer Gill

AMPCO INTERROGATORY #65

Reference:
F-01-06 p.7

Interrogatory:
Please provide a breakdown of the outsourcing costs in 2020.

Response:
The Outsourcing department oversees third party contracts with Inergi. The cost is related to labour. As evidenced in Exhibit F-01-06 p.2 Table 2, Outsourcing department transmission allocated cost for 2020 is $0.3M.

Witness: Spencer Gill

AMPCO INTERROGATORY #66

Reference:
F-01-07 p.5

Interrogatory:
Please provide a breakdown of External Purchased Services for the years 2015 to 2018 (plan vs actuals) and forecast for 2019 and 2020.

Response:
External Services include BGIS (Brookefield Global Integrated Services) and services provided by temporary resources as described in F-01-07 pages 2 & 6.

Exhibit F-03-01 provides details regarding the BGIS contract as well as its associated costs found in Appendix B.

Interrogatory I-12-AMPCO-54 provides details regarding a small portion of forestry work that is provided by external resources.

Exhibit F-04-01 Attachment 5 updated in Interrogatory I-07-SEC-58 provides details regarding temporary transmission labour costs.

AMPCO INTERROGATORY #67

Reference:

F-01-07 p.5

Interrogatory:

Please provide Hydro One's resource utilization rate for the years 2015 to 2018 and show the calculation.

Response:

It is unclear what "resource utilization rate" refers to as it is not stated on pg. 5 of F-01-07 and Hydro One is unable to provide a response.

AMPCO INTERROGATORY #68

Reference:
F-01-07

Interrogatory:
Please explain the term “windshield time”.

Response:
Windshield Time is used to describe the time workers spend driving, the idea behind some productivity initiatives is to have workers spending less time driving and more time on the tools. (i.e. Temporary Work Headquarters)

Witness: Andrew Spencer

AMPCO INTERROGATORY #69

Reference:
F-01-07

Interrogatory:
Please provide the wrench studies completed in 2016 and 2017.

Response:
Internal reviews were completed for Maintenance activities in an effort to true-up estimates and identify areas for improvement in wrench time to be actioned.

Estimates were adjusted on average by approximately 3.5% based on the results of the work studied.

Below is a list of the Wrench Time Studies completed.

Year Studied	Task description	Studies Completed	SAP Estimate	Average Historical Hours Charged 2012 to 2015	Average Actual Hours Observed	Suggested New Estimate
2017	Breaker Diagnostic Testing	1	3	1.6	9.0	2
2017	Breaker Selective Intrusive inspection	2	7	7.0	10.3	NC
2017	Transfer Switch Diagnostic Testing	1	3	1.7	9.5	NC
2016	Breaker Diagnostic/Function/Selective Intrusive Testing	2	250	182.5	142.5	188
2016	Breaker Diagnostic/Function/Selective Intrusive Testing	3	71	77.2	74.9	NC
2016	Breaker Diagnostic/Function/Selective Intrusive Testing	3	316	217.7	127.4	146
2017	Breaker Diagnostic/Function/Selective Intrusive Testing	2	110	123.9	104.9	NC
2016	Station Visual Power Equipment Inspections	3	10	7.5	5.4	8

Witness: Andrew Spencer

Year Studied	Task description	Studies Completed	SAP Estimate	Average Historical Hours Charged 2012 to 2015	Average Actual Hours Observed	Suggested New Estimate
2016	Station Visual Power Equipment Inspections	2	14	11.9	8.6	10
2016	Station Visual Power Equipment Inspections	2	18	15.0	11.6	12
2016	Station Visual Power Equipment Inspections	2	24	21.0	16.8	18
2016	Station Visual Power Equipment Inspections	1	30	23.0	45.5	NC
2016	Station Visual Power Equipment Inspections	2	65	54.9	36.8	48
2016	Tap Changer Selective Intrusive Inspection	3	31.5	29.4	65.8	39
2016	Tap Changer Selective Intrusive Inspection	2	54	43.4	73.9	NC
2017	Station Battery Charger Diagnostics Inspection	3	6	5.5	10.5	NC
2017	Station Battery Diagnostics Inspection	1	14	11.8	14.5	8
2017	Station Battery Visual Inspection	1	4	3.1	14.5	3.5
2017	Station Battery Function Testing	2	5	5.0	10.3	NC
2017	Station Battery Diagnostics Inspection	2	13	12.2	16.0	12
2017	Station Battery Visual Inspection	1	4	3.7	4.0	3
2017	Station Battery Visual Inspection	1	3.5	3.2	8.0	3.5
2017	Station Battery Diagnostics Inspection	2	11	9.3	9.5	8
2017	Station Battery Function Testing	2	3.4	3.5	8.0	NC
2016	Tap Changer Selective Intrusive Inspection	3	36	24.1	50.9	NC
2017	Tap Changer Selective Intrusive Inspection	1	42	41.1	57.8	NC
2017	Switch Selective Intrusive Inspection	1	21	16.9	50.0	NC
2016	Switch Selective Intrusive Inspection	3	9	6.6	18.8	NC
2016	Switch Selective Intrusive Inspection	2	13.5	9.5	24.9	NC

Witness: Andrew Spencer

Year Studied	Task description	Studies Completed	SAP Estimate	Average Historical Hours Charged 2012 to 2015	Average Actual Hours Observed	Suggested New Estimate
2016	Switch Selective Intrusive Inspection	3	14	12.7	24.0	18

AMPCO INTERROGATORY #70

Reference:
F-01-07

Interrogatory:
a) Please provide the total number of hours worked (excluding overtime) 2014 to 2018 and the forecast for 2019 and 2020.

b) Please provide Hydro One's overtime hours for the years 2014 to 2018 and the forecast for 2019 and 2020.

c) Please summarize the key work activities that require overtime.

Response:
a)

Non Overtime Hours	2015	2016	2017	2018
Non Represented	1,057,992	1,087,375	1,128,812	1,138,661
Society	1,939,271	1,906,495	1,941,201	2,001,730
PWU	5,282,870	5,312,499	5,214,769	5,334,730
Non Regular	5,088,766	5,506,531	5,020,948	5,066,686

b)

Overtime Hours Worked	2015	2016	2017	2018
Society	67,133	68,571	74,889	92,197
PWU	672,123	698,085	682,826	848,107
Non Regular	264,163	266,165	247,519	421,904

Due to unpredictability of overtime hours, Hydro One does not forecast future overtime hours. Forecasted overtime spend, based on historical spend for forecast years can be found in Exhibit I, Tab 7, Schedule SEC-58.

c) Please refer Exhibit I, Tab 2, Schedule EnergyProbe-16

Witness: Andrew Spencer, Sabrin Lila

AMPCO INTERROGATORY #71

Reference:

F-04-01 p.3

Interrogatory:

Please provide a breakdown of the number of Management Staff by Management category for the years 2014 to 2018 and forecast for 2019 to 2022. Levels 5-10 are catergorized as management and Levels 1-4 are defined as non-represented.

Response:

Please refer to Exhibit I, Tab 12, Schedule AMPCO-76.

AMPCO INTERROGATORY #72

Reference:

F-04-01 p.5

Interrogatory:

a) Please provide contract staff costs for each of the years 2014 to 2018 by work program.

b) Please provide the 2019 to 2022 forecast cost for contract staff and explain how the budget was derived.

Response:

a) Please see Exhibit I, Tab 01, Schedule OEB-194 for 2016 – 2018 contract staff costs. The 2015 contact staff costs are not available. The data for 2015 is not comparable following the implementation of a new contract management system.

b) Hydro One looks to control contractor costs through an approval process. Forecast for contractor spend is not available.

Witness: Sabrin Lila

AMPCO INTERROGATORY #73

Reference:
F-04-01 p.6

Interrogatory:
a) Please provide the number of eligible retirements and actual retirements for each of the years 2014 to 2018.

b) Please provide the number of forecast retirements for 2019 to 2022.

c) How does Hydro One account for retirements in the Compensation budget for the test years?

Response:
a) Please see Exhibit I, Tab 07, Schedule SEC-53 part a)

b) Forecasted retirements are estimated based on the assumption that 20% of the employees eligible for an unreduced pension will retire.

Year	Forecasted Retirements
2019	169
2020	166
2021	146
2022	137

c) Retirements are generally pre-planned to be replaced by successors where work load requires a replacement. There is minimal impact on the compensation budget as a result of retirements.

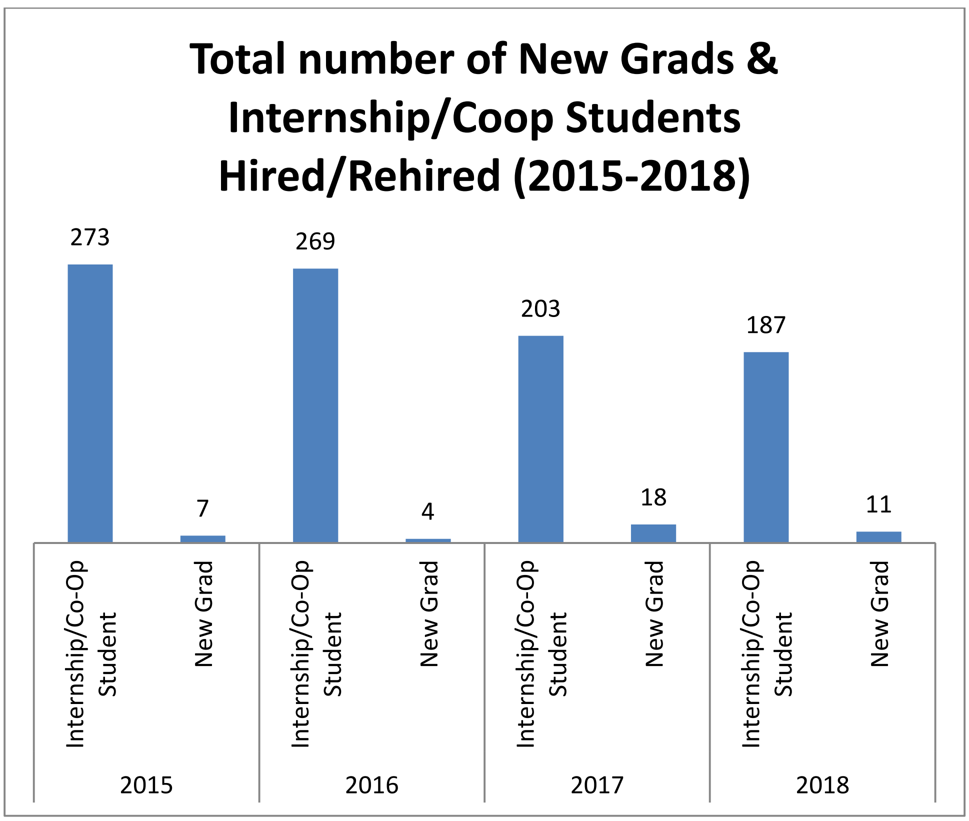
Witness: Sabrin Lila

AMPCO INTERROGATORY #74

Reference:
F-04-01 p.10

Interrogatory:
Please provide the number of co-op program graduate trainee hires compared to trainees for the years 2014 to 2018.

Response:
Hydro One hired 932 co-op program graduates and 40 new graduates trainee hires from 2015 - 2018.



Witness: Sabrin Lila

AMPCO INTERROGATORY #75

Reference:
F-04-01 p.12

Interrogatory:
a) Please discuss the need and objectives of the new Operational Workforce Planning initiative and the expected outcomes.

b) Please discuss the need and objectives of the new Strategic Workforce Planning initiative and the expected outcomes.

Response:
a) The Operational Workforce Planning initiative is focused on a 1-year headcount and resource planning cycle aligned with business planning. The expected outcomes include: 1) Budgeted headcount aligned to business planning, 2) Headcount needs aligned to workforce strategy, 3) Headcount managed to accurately reflect business needs, and 4) Additional insight for Talent Management to proactively plan recruitment and succession activities.

b) The Strategic Workforce Planning initiative is focused on a 5-year headcount planning cycle. The expected outcomes include: 1) 5-year budgeted headcount aligned to business planning, 2) In-depth planning strategy related to a subset of specific jobs, and 3) Identification of long-term talent needs to achieve business objectives.

Witness: Sabrin Lila

AMPCO INTERROGATORY #76

Reference:

F-04-01 p.13 Table 2

Interrogatory:

a) Please recast Table 2 showing a breakdown of MCP employees between Management and non-represented staff.

b) Please add the years 2014 to 2016 to the Table.

c) Please provide an excel version of the revised Table 2.

Response:

a) Please see table below

b) Please see table below

c) See attached excel file

Witness: Sabrin Lila

Table 2: Full Time Equivalents (FTE), 2017 to 2022

		2015	2016	2017	2018	2019	2020	2021	2022
Regular	Management	274	280	291	293	318	319	319	319
	Non represented	323	328	342	345	374	374	375	375
	Society	1282	1267	1289	1337	1577	1565	1566	1560
	PWU	3356	3391	3382	3527	3739	3790	3824	3852
	Total Regular	**5235**	**5266**	**5304**	**5502**	**6008**	**6048**	**6084**	**6106**
Temporary	Management	13	3	1	1	0	0	0	0
	Non represented	16	27	17	21	6	6	6	6
	Society	55	47	36	28	13	12	9	9
	PWU	212	230	194	173	99	98	98	98
	Total Temporary	**296**	**307**	**248**	**223**	**118**	**116**	**113**	**113**
Casual	PWU Hiring Hall	1245	1389	1230	1351	1794	1717	1781	1782
	Casual Trades	1301	1402	1364	1353	1296	1265	1205	1159
	Total Casual	**2546**	**2791**	**2594**	**2704**	**3090**	**2982**	**2986**	**2941**
	Grand Total	**8077**	**8364**	**8146**	**8429**	**9216**	**9146**	**9183**	**9160**

Note: Management and Non Represented are both in the MCP category. In accordance with the definition from AMPCO IR number 71 where it is defined that Levels 5-10 are categorized as management and Levels 1-4 are defined as non-represented.

Note: Consistent with filing requirements, only 2015 and forward years data is provided

AMPCO INTERROGATORY #77

Reference:

F-04-01

Interrogatory:

For each of the years 2015 to 2018, please complete the following table:

Headcount	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Jan 1												
Hires												
Retirements												
Other Exits												
Vacancy Lag												

FTEs	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Jan 1												
Hires												
Retirements												
Other Exits												
Vacancy Lag												

Response:

The following tables were populated for regular employees, which correspond with retirements and other exits. The vacancy lag is the average number of days to fill a vacancy per month. For regular staff, Hydro One assumes 1 headcount equals 1 FTE. Hires include external hires only (excludes internal moves).

2015

Headcount	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Jan 1	**5278**	**5272**	**5260**	**5246**	**5239**	**5229**	**5218**	**5213**	**5247**	**5246**	**5248**	**5239**
Hires	2	7	5	5	4	5	7	2	5	9	4	1
Retirements	-18	-8	-18	-23	-18	-15	-32	-12	-15	-12	-7	-8
Other Exits	-5	-4	-1	-5	-0	-3	-8	-3	-0	-4	-0	-2
Vacancy lag	91	91	79	69	75	99	96	106	82	87	75	65

2016

Headcount	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Jan 1	**5299**	**5282**	**5285**	**5277**	**5260**	**5265**	**5227**	**5264**	**5282**	**5271**	**5263**	**5303**
Hires	2	3	10	4	6	18	2	10	10	7	3	3
Retirements	-16	-11	-17	-11	-15	-6	-40	-19	-23	-14	-13	-14
Other Exits	-6	-4	-4	-3	-5	-11	-4	-4	-1	-7	-1	-5
Vacancy lag	75	84	75	83	84	76	80	75	78	84	86	91

2017

Headcount	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Jan 1	**5364**	**5357**	**5381**	**5368**	**5344**	**5326**	**5284**	**5266**	**5250**	**5258**	**5237**	**5231**
Hires	21	9	16	7	12	7	8	5	8	23	9	10
Retirements	-35	-19	-15	-19	-27	-17	-45	-27	-28	-15	-12	-19
Other Exits	-4	-6	-6	-8	-16	-11	-14	-3	-5	-6	-12	0
Vacancy lag	71	77	108	94	81	88	81	84	89	69	77	98

2018

Headcount	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Jan 1	**5268**	**5263**	**5505**	**5564**	**5511**	**5566**	**5532**	**5519**	**5512**	**5566**	**5553**	**5553**
Hires	9	10	261*	28	17	14	12	8	9	31	16	3
Retirements	-31	-10	-13	-18	-18	-8	-38	-17	-14	-6	-13	-14
Other Exits	-21	-9	-9	-9	-7	-6	-14	-9	-7	-7	-20	0
Vacancy lag	78	86	105	109	110	103	103	81	55	80	91	85

**Includes employees added as part of the CSO acquisition on March 1, 2018*

Note: monthly headcount cannot be derived by taking previous month headcount, adding hires, and subtracting retirements and other exists, due to the following reasons:

1. Employees who move from casual or temporary to regular, do not count as an external hire, but would increase headcount.
2. Employees moving on or off of a long term leave will impact the headcount, without impacting hires, retirements or exits.
3. Hires, retirements and other exits completed close to month-end may not impact headcount until the following month.

AMPCO INTERROGATORY #78

Reference:

F-04-01 p.14

Interrogatory:

Hydro One indicates that total regular and non-regular FTES increase over the 2019 to 2022 period due in part to support a 26% increase in the Transmission work program.

a) Please provide a breakdown of the 26% by work program.

Response:

a) Please refer to Table 7 of Exhibit A, Tab 3, Schedule 1 for a breakdown of major capital categories and OM&A expenditures.

Witness: Sabrin Lila

AMPCO INTERROGATORY #79

Reference:

F-04-01

Interrogatory:

Please provide Hydro One's latest H/R staffing metrics.

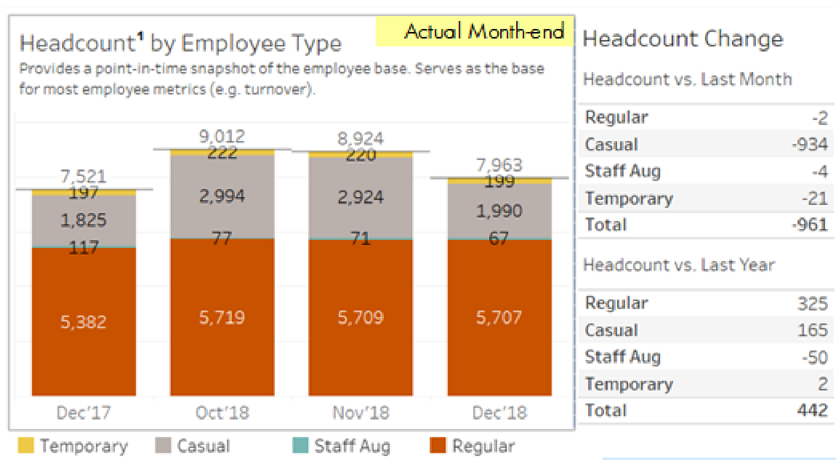
Response:

Hydro One provides the executive leadership team with reports on headcount and turnover on a monthly basis and additional metrics such as employee demographics.

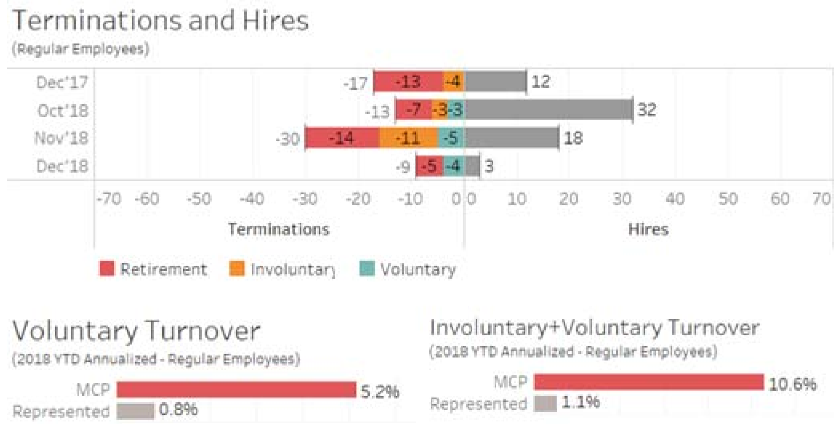
Note: This reporting is inclusive of all subsidiaries (including Hydro One Remotes and Hydro One Telecom).

Below is an example of what is included in the monthly reports.

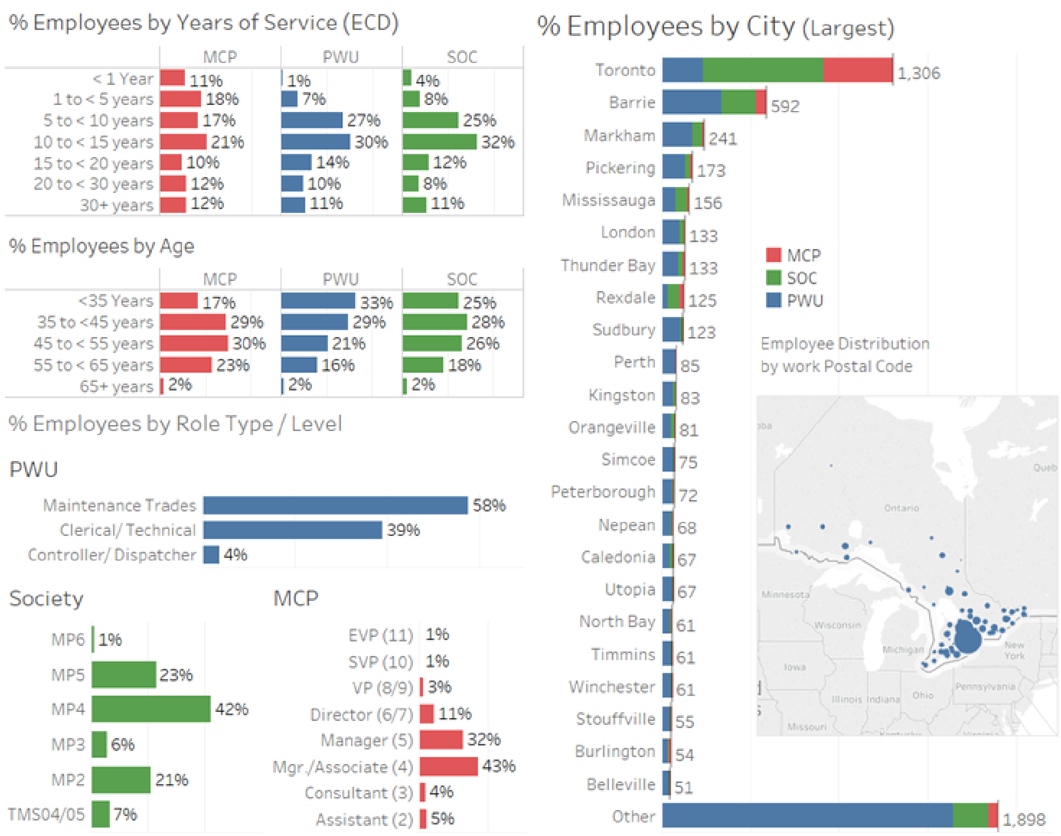
Headcount at end-month:



Terminations and hires reporting for regular employees:



Employee Demographic Metrics (as of January 2019):



AMPCO INTERROGATORY #80

Reference:

F-04-01 p.19 Table 3

Interrogatory:

At Table 3, Hydro One provides principles that inform the various compensation elements for MCP employees.

a) Please discuss if there are different weightings for each principle.

Response:

a) Hydro One takes a holistic view of the compensation principles and does not prescribe weightings to individual principles.

AMPCO INTERROGATORY #81

Reference:
EB-2016-0160 Exhibit C-04-01 p.7

Interrogatory:
Please update Figure 4 with actuals for 2016, 2017 and 2018 and include the forecast for 2019 to 2022.

Response:
Please see Exhibit F, Tab 4, Schedule 1 page 33-34 Figures 5 and 6. Note that the current evidence shows total employee compensation while Figure 4 in EB-2016-0160 showed only regular employees.

Witness: Sabrin Lila

AMPCO INTERROGATORY #82

Reference:

F-04-01 p.24

Interrogatory:

Hydro One indicates that individual merit increases are determined by demonstrated performance and comp-ratios.

By way of example, please explain how compa-ratios contribute to merit pay.

Response:

For MCP employees, when determining the annual merit increase Hydro One considers both an employee's performance and their positioning within the relevant salary structure (compa-ratio). In general, an employee who is positioned lower in the salary structure will receive a higher percentage merit increase than an employee positioned higher in the structure (for commensurate performance).

AMPCO INTERROGATORY #83

Reference:
F-04-01

Interrogatory:
Hydro One provides the 2019 Team Scorecard.

Please provide the Team Scorecards for the years 2014 to 2018.

Response:
Please see Attachment 1 for 2015-2016 team scorecards.
Please see Attachment 2 for 2017 team scorecard.
Please see Attachment 3 for 2018 team scorecard.

Witness: Sabrin Lila

APPENDIX

HYDRO ONE INC.

Recommended 2015/2019 Corporate Scorecard[1,2,3]

Strategic Objective	Performance Measure	2014 Target	2014 Actual	Targets 2015	Targets 2019
Injury Free Workplace	Total Recordable Rate (OHSA Recordable) # Recordable per 200,000 hours worked	1.9	1.8	1.7	0.9
Satisfying our Customers	**Customer Satisfaction – Transmission[4] (% satisfied)**	**n/a**	**76**	**78**	**90**
	Customer Satisfaction – Distribution[4] (% satisfied)	**n/a**	**84**	**86**	**90**
	Connection of New Services (% completed in ≤ 5 days)	90	97	95	95
	Billing Success (NEW) (%)	**n/a**	**97**	**99**	**n/a**
	First Call Resolution (NEW) (%)	**n/a**	**81**	**83**	**87**
Continuous Improvement & Cost Effectiveness in the Building and Maintaining of Reliable Distribution and Transmission Systems	Transmission Unit Costs (OM&A/Gross Fixed Assets)[5] %	2.9	2.7	2.8	2.5
	Distribution Unit Costs (OM&A/Gross Fixed Assets)[5] %	5.7	6.1	5.4	4.7
	Duration (SAIDI) – Transmission (minutes per delivery point)	8.9	11.8	10.0	8.8
	Duration (SAIDI) – Distribution (hours per customer)	6.7	7.4	7.1	6.9
Maintaining a Commercial Culture that Increases Shareholder Value	Net Income After Tax ($M)[5]	668	747	750	941
	In-Service Capital – Transmission (% of Plan)[5]	85	99	95	100
	In-Service Capital – Distribution (% of Plan)[5]	87	97	95	100

[1] New measures are in bold.

[2] 2015 targets are based on historical data, benchmarking (where available) and approved Business Plans. Targets reflect the Company's strategic objectives and consideration of the audited 2014 year-end results for review and approval by the accountable Executive and Hydro One Committees and Board.

[3] Safety, including major safety events, will be an important consideration of the Board in determining the level of short term incentive pool.

[4] The Customer satisfaction measures have moved away from measuring top-line customer satisfaction and instead shifted to measuring satisfaction with relevant business processes and transactional customer experience. The Distribution Customer Satisfaction measure also includes an additional transactional survey called "My Account".

[5] The targets do not reflect the impact of the Distribution Rate decision. Targets will be updated once the 2015 Business Plan and Gross Fixed Assets numbers are released.

Executive Summary

2016 Team Scorecard					
	Weight	Threshold	Target	Maximum	Description
Net Income	**50%**	582.2	685.0	736.0	$M
Customer Sat.	**20%**	74%	75%	80%	% Customer Satisfaction
Work Program	**20%**	97%	101%	106%	% Work Program Complete
Safety*	**10%**	1.7	1.6	1.5	Recordable Rate per 200,000 Hrs.

* *If the company has a fatality, the attained Safety measure will be reduced by 50% based on the findings of the System Investigation*

The 2016 Team Scorecard is developed to provide feedback that helps ensure the Company remains on track to achieving its Strategic Objectives.

The Team Scorecard is made up of four weighted measures (with a minimum of 10% given to any one measure) with the majority weighting on the financial measure.

The 2016 Team Scorecard is a key input into 2016 Management Compensation, specifically the Short Term Incentive Plan (STIP) Fund, as it relates to overall corporate performance in 2016.

Each Scorecard measure includes performance expectations expressed as Threshold/Target/Maximum to provide clear expectations at the Company level that can be translated into personal expectations for achievement.

Team Performance, expressed by the Team Scorecard, plays an increasingly larger role in Management Compensation based on level.

Bank	Team Weighting	Individual Weighting
Sr. Exec. (1-2)	80%	20%
Exec. (3-4)	80%	20%
Director (5)	70%	30%
Mgmt./Prof. (6-7)	70%	30%
Support (8-10)	50%	50%

The combination of these four performance measures are expected to drive the following behaviours:

1. A focus on finding ways to maximize net earnings without compromising work program delivery.
2. Focusing the organization on achieving activities that are meaningful and impactful to customers, in addition to continuing the focus on ensuring positive transactional outcomes.
3. Making it clear to the organization that an appropriate balance between satisfying all stakeholders, including ratepayers, shareholders and customers is the path to maximizing value.
4. Reinforcing the continuing importance of safety to the organization.
   NOTE: This metric has a modifier attached to it, which will require that, in the case of a fatal incident, the overall safety measure will be reduced by 50%. This appropriately demonstrates a fatality on our watch is unacceptable and must be heavily weighted.

Team Scorecard

2017 Team Scorecard

Corporate Goal	Component Weight	Definition	Measure	Sub Component Weight	2017 Performance Levels		
					Threshold	Budget	Maximum
Health and Safety *	10%	Recordable Incidents	Incidents per 200,000 hours	100%	1.6	1.1	1.0
Work Program	25%	Reliability – Tx (SAIDI) average length of unplanned interruptions to multi-circuit supplied delivery points	Minutes per Delivery Point	25%	10.0	9.6	9.2
		Reliability -Dx (SAIDI) average length of outages in hours that a customer experiences	Hours per Customer	25%	7.8	7.5	7.2
		Tx In Service Additions Delivery Accuracy	Variance (%) to approved budget of $931M (Tx Application)	25%	+/- 7%	+/- 5%	+/- 2%
		Dx In Service Additions Delivery Accuracy	Variance (%) to approved budget of $663M	25%	+/- 6%	+/- 4%	+/- 2%
Net Income	30%	Net Income to Common Shareholders	$M	100%	Note 1	Note 1	Note 1
Productivity	10%	Productivity Savings (Capital and OM&A)	$	100%	$64.3 (-10%)	$70.7	$77.7 (+10%)
Customer	25%	Dx Satisfaction - Improve overall Small and Residential Dx customer satisfaction	Customer Satisfaction	50%	70%	72%	75%
		Tx Satisfaction - Improve overall Large Tx customer satisfaction	Customer Satisfaction	50%	80%	82%	85%

** If the company has a fatality, the attained Safety measure will be reduced by 50% based on the findings of the System Investigation*
Note 1: As we are a public company, we cannot communicate full year net income budgets widely

2018 Team Scorecard

Corporate Goal	Component Weight	Definition	Measure	Sub Component Weight	Performance Levels		
					Threshold	Budget	Maximum
Health and Safety *	10%	Recordable Incidents	Incidents per 200,000 hours	100%	1.3	1.1	1.0
Work Program	25%	Transmissions (Tx) Reliability – average length of unplanned interruptions to multi-circuit supplied delivery points (SAIDI)	Minutes per Delivery Point	25%	9.2	7.6	5.4
		Distribution (Dx) Reliability – average length of outages in hours that a customer experiences (SAIDI)	Hours per Customer	25%	7.5	7.0	6.8
		Tx In Service Additions - Delivery Accuracy	Variance (%) to approved budget of $1,174M (Tx following OEB decision)	25%	+/- 6%	+/- 4%	+/-1%
		Dx In Service Additions - Delivery Accuracy	Variance (%) to approved budget of $641M (Dx Application)	25%	+/- 5%	+/- 3%	+/-1%
Net Income	30%	Net Income to Common Shareholders	$M	100%	redacted	redacted	redacted
Productivity	10%	Savings in $M	$M	100%	$103.1	$114.5	$140.0
Customer	25%	Residential and Small Business customer satisfaction	Customer Satisfaction	50%	71%	73%	76%
		Tx (including Dx connected LDCs) customer satisfaction	Customer Satisfaction	50%	84%	86%	90%

** If the company has a fatality, the attained Safety measure will be reduced by 50% based on the findings of the System Investigation*

AMPCO INTERROGATORY #84

Reference:
F-04-01-05

Interrogatory:
Please provide an excel version of Attachment 5.

Response:
Please see Exhibit I, Tab 07, Schedule SEC-58 Attachment 1.

Witness: Sabrin Lila

AMPCO INTERROGATORY #85

Reference:

F-04-01

Interrogatory:

Please provide a table that sets out Hydro One's compensation costs as a percentage OM&A and Capital for the years 2014 to 2018 and forecast for 2019 and 2020.

Response:

	2014	2015	2016	2017	2018	2019	2020
Compensation $ as % of Work Program	48%	46%	44%	47%	47%	49%	48%

AMPCO INTERROGATORY #86

Reference:
F-04-01

Interrogatory:
a) Please provide Hydro One's absenteeism rate for the years 2014 to 2018.

b) Please provide Hydro One's turnover rate for the years 2014 to 2018.

Response:
The information presented below includes regular employees only, so as not to weight the figures with temporary or casual employees – many of which are not part of the workforce for the entire year.

a) The absenteeism rates (the average number of sick days taken) of regular employees for the years 2015 to 2018 are as follows:

Year	Absenteeism Rate[1]
2015	7.4 days
2016	8.0 days
2017	7.8 days
2018	8.0 days

[1] The absenteeism rate excludes outliers with greater than 90 days of absence.

b) Hydro One turnover rates of regular employees for the years 2015 to 2018 are as follows:

Year	Turnover Rate
2015	4.2%
2016	4.8%
2017	6.9%
2018	5.6%

Hydro One turnover includes retirements, as well as voluntary and involuntary turnover. The higher turnover rate in recent years is largely attributable to increasing retirements (please see Exhibit I, Tab 08, Schedule PWU-014) and increasing MCP turnover, possibly related to the introduction of a defined contribution pension which is allows for greater mobility.

AMPCO INTERROGATORY #87

Reference:
F-04-01

Interrogatory:
Please provide a table that compares forecast and actual depreciation for the years 2015 to 2018.

Response:
Please see below for a comparison of Board approved amounts and actuals for 2015 through 2018, for Transmission.

Description	2015			2016			2017			2018		
	OEB Approved	Historical	Variance	OEB Approved	Historical	Variance	OEB Approved	Historical	Variance	OEB Approved	Historical	Variance
Depreciation on Fixed Assets	349.2	339.0	(10.2)	364.1	350.8	(13.3)	381.3	370.6	(10.7)	402.0	387.3	(14.7)
Less: Capitalized Depreciation	(6.4)	(9.0)	(2.6)	(6.7)	(12.0)	(5.3)	(12.1)	(12.6)	(0.5)	(12.8)	(13.0)	(0.2)
Asset Removal Costs	38.1	29.0	(9.1)	33.7	34.6	0.9	53.4	38.3	(15.1)	69.2	37.7	(31.5)
Losses/ (Gains) on asset disposition	-	-	-	-	(0.1)	(0.1)	-	(2.0)	(2.0)	-	(0.5)	(0.5)
Total	**380.9**	**359.0**	**(21.9)**	**391.1**	**373.3**	**(17.8)**	**422.6**	**394.3**	**(28.3)**	**458.4**	**411.5**	**(46.9)**

**figures in millions*

Witness: Samir Chhelavda

AMPCO INTERROGATORY #88

Reference:

I1-01-02 p.4

Interrogatory:

Please discuss if Hydro One has made any changes to what is included as a network asset since the methodology was first approved and provide details.

Response:

As stated in the evidence at Exhibit I1, Tab 1, Schedule 2, page 3, lines 20-23, to align with the OEB's Decision in Proceeding EB-2011-0043, the meaning of a Network asset has expanded to include certain assets captured under the previous definition of a Line Connection asset that provide other functions beyond supplying load.

Witness: Clement Li