ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998 c.15 (Schedule B), s. 78.

AND IN THE MATTER OF an application by Hydro One Networks Inc. to raise its electricity distribution rates effective January 1, 2018 and continuing each year for another 4 years, until December 31, 2022.

EB-2017-0049

CROSS-EXAMINATION COMPENDIUM

PANEL 5

ANWAATIN INC.

June 21, 2018

TAB 1

1.4 (5.2.3) PERFORMANCE MEASUREMENT AND OUTCOME MEASURES

The Renewed Regulatory Framework (RRF) is an outcomes-based approach to regulation. Hydro One recognizes the need to demonstrate how it will achieve the four RRF outcomes: customer focus, operational effectiveness, financial performance and public policy responsiveness. The Electricity Distributor Scorecard, including the targets (Exhibit A, Tab 5 Schedule 1), shows Hydro One's success achieving these outcomes and the performance levels that Hydro One expects to achieve over the 2018 to 2022 rate setting period.

In addition to the measures already reported through this scorecard, Hydro One is proposing to report on several additional performance measures in its Distribution Scorecard that also demonstrate the distribution system outcomes the Company provides. Hydro One is committed to both sets of performance measures as it evaluates its progress executing its 2018 to 2022 investment plan that aligns the needs and preferences of customers, compliance and condition needs of Company assets, and rate impacts. Hydro One's plan has a number of initiatives that control costs, increase productivity and maintain levels of reliability in rural and urban areas. These are all outcomes that customers have indicated they value, are central to Hydro One's Business Objectives, and the OEB's Renewed Regulatory Framework.

1.4.1 (5.2.3 A AND B) METHODS AND MEASURES

In considering outcome measures to be included in scorecards, Hydro One identified potential metrics drawn from internal and external sources that include Hydro One's past performance management metrics, benchmarking studies, and scorecards and metrics of other utilities in the public domain. The selection process was also guided by the OEB's

Handbook for Utility Rate Applications, which indicates the OEB will evaluate proposed outcomes and performance metrics using the following key considerations:

- A focus on strategy and results, not activities;
- The need to demonstrate continuous improvement;
- Outcomes that are demonstrated to be of value to customers; and
- Performance metrics that will accurately measure whether outcomes are being achieved, and that include stretch goals to demonstrate enhanced effectiveness and continuous improvement.

The Distribution OEB Scorecard provided in the table below, includes the metrics that Hydro One is proposing to report on and includes targets for 2018. Hydro One proposes to report the results on an annual basis or as determined by the OEB. As described in the attached Productivity Reporting Governance Document (DSP Section 1.4, Attachment 1), Hydro One operations managers and the Executive Leadership Team will be reviewing progress on these metrics on a regular basis. This reporting and governance structure will allow Hydro One's management to assess progress towards targets and determine corrective action, when warranted, to help ensure that a performance or outcome measure is effective and does not result in unintended consequences. Hydro One will be considering these metrics in its business planning processes and will be setting new targets on an annual basis.

Table 8 – Distribution OEB Scorecard

			Historical Results						Target	
RRF Outcomes		**Measure**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Customer Focus	Customer Satisfaction	Customer Satisfaction - Perception Survey %	77%	78%	80%	67%	70%	66%	72%	74%
		Handling of Unplanned Outages Satisfaction %	81%	79%	78%	75%	76%	75%	76%	77%
		Call Centre Customer Satisfaction %	85%	84%	82%	81%	85%	86%	86%	87%
		My Account Customer Satisfaction %	81%	84%	64%	75%	78%	79%	81%	83%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in $	8,541	8,441	7,824	8,928	8,392	8,350	8,640	8,733
		Vegetation Management - Gross Cyclical Cost per km $	New Program						9,441	9,382
		Station Refurbishments - Gross Cost per MVA in $*	386,000	-	318,000	348,000	500,000	557,000	461,000	454,000
		OM&A dollars per customer	456	451	498	551	453	455	449	455
		OM&A dollars per km of line	4,723	4,676	5,109	5,654	4,719	4,773	4,700	4,758
	System Reliability	Number of Line Equipment Caused Interruptions	7,681	7,316	7,266	8,311	8,164	7,674	8,200	8,200
		Number of Vegetation Caused Interruptions	6,113	6,953	5,791	6,540	6,944	7,439	6,900	6,500
		Number of Substation Caused Interruptions	159	144	129	158	141	103	145	145
		SAIDI - Rural - duration in hours	8.2	8.2	8.1	8.6	9.1	9.1	9.1	9.0
		SAIFI - Rural - frequency of outages	3.3	3.3	3.0	3.4	3.4	3.1	3.4	3.4
		SAIDI - Urban - duration in hours	2.7	3.2	2.2	2.8	2.8	2.4	2.8	2.8
		SAIFI - Urban - frequency of outages	1.6	1.7	1.6	2.3	1.4	1.6	1.7	1.7
		Large Customer Interruption Frequency (LDA's) - frequency of outages	New Measure		135	197	228	136	143	143

*There were no station refurbishment units matching the criteria completed in 2012

Witness: Michael Vels/Greg Kiraly/Darlene Bradley

Customer Focus Measures

Customer Satisfaction – Perception Survey %

Hydro One included this metric for reporting as part of its previous distribution rates application (EB-2013-0416), referred to as 'Residential and Small Business Satisfaction' at that time. Hydro One proposes to continue reporting this metric as part of this Application. Hydro One measures customers' perception of the Company as a whole, whether they have interacted with Hydro One recently or not. The survey indicates how well the Company meets customers' expectations. The perception surveys are conducted twice per year by an external service provider, who contacts randomly selected customers. The reported results reflect what customers have indicated as their overall satisfaction with Hydro One. Although the results may be influenced by the overall price of electricity on a customer's bill, Hydro One still seeks to improve its score on this measure.

Handling of Unplanned Outages Satisfaction

Hydro One began reporting this metric as part of its previous distribution rates application (EB-2013-0416) and proposes to continue reporting it as part of this Application. This metric measures customers' satisfaction of Hydro One's handling of a customer's last unplanned outage. The Handling of Unplanned Outages was indicated as a source of frustration for customers during recent customer consultation, as described in Section 1.3 of the Distribution System Plan. Satisfaction is measured through the results of a survey that Hydro One conducts in two segments per year, targeting 1,200 interviews per segment. The telephone survey contacts a random sample of customers that have called into Hydro One's customer centre over the previous 12 months. Customers are asked if they have experienced an unplanned outage over the last 6 months. Those respondents that answer "yes" are then asked how satisfied they are with the way Hydro One handled the most recent unplanned outage.

Call Centre Customer Satisfaction

This metric is newly proposed as part of this Application and is intended to measure customer satisfaction with services provided by Hydro One's call centre, which is often the first point of contact Hydro One has with a customer when they have a question or an issue that needs to be resolved. Customer satisfaction after the call is a strong indication of whether or not a customer inquiry has been addressed appropriately. This metric demonstrates that services are being provided in a manner that is responsive to customer needs. The call centre customer satisfaction survey occurs shortly after the phone call, which allows the call centre to capture timely and accurate information and to address any areas for improvement.

My Account Customer Satisfaction

This metric is newly proposed as part of this Application and is intended to measure customer satisfaction with services delivered by Hydro One's My Account web portal. My Account allows customers to find the information they need so that they can manage their bills and electricity usage. With My Account, Hydro One is able to provide customers with the information and services they are seeking in a convenient, efficient manner. This measure will demonstrate whether the services are being provided in a manner consistent with customer expectations. The satisfaction level is determined by using an online survey, which is emailed to customers through a third party and contains a link inviting them to take part in the survey. This email is sent out to customers who have accessed and logged on to My Account within the past two days.

Operational Effectiveness Measures

Hydro One's customers have indicated that effective cost management and efficiency are outcomes that they value. The following metrics are designed to measure and track Hydro One's operational effectiveness.

Pole Replacement – Cost per Pole

This metric is newly proposed as part of this Application. This cost per unit metric will demonstrate how successful Hydro One is in delivering productivity improvement in this area. In addition, the pole replacement program has been an area of interest in previous applications, with the OEB directing Hydro One to complete a benchmarking study to support this Application. Hydro One completed this study through Navigant and First Quartile, which can be found in Section 1.6 of the Distribution System Plan. This metric will allow for benchmarking over time and will allow for cost per unit comparisons with other distributors. There are many factors that could impact the average cost per pole such as whether it is going into earth or rock, or the height and type of pole required. These circumstances will change the cost of poles and will cause fluctuations within the program, which is why the programs cost per unit should be viewed as a trend versus an individual year. In addition to providing useful information on cost trending, variances in performance between periods will also inform management on factors affecting costs and enable corrective actions and improvements to be made.

$$= \frac{Total\ Cost\ of\ Pole\ Replacement\ Program}{Number\ of\ Poles\ Replaced}$$

Vegetation Management – Cost per KM

This metric is newly proposed as part of this Application. This cost per unit metric will demonstrate how successful Hydro One is at delivering productivity improvement in its vegetation management program. In addition, this program has been an area of interest in previous applications, with Hydro One directed by the Board to complete a benchmarking study to support this Application. Hydro One has completed this study through CN Utility Consulting, Inc., which can be found in Section 1.6 of the

Distribution System Plan. This metric will allow for benchmarking over time and will allow for cost per unit comparisons with other distributors.

There are many factors that affect the average cost per unit for vegetation management, including the density of vegetation and the remoteness of the location. These factors have a significant impact on the costs related to the program which is why the average cost per unit should be viewed as a trend rather than an individual year. This measure is the dollar cost per km of cyclical line cleared.

$$= \frac{Cost\ of\ Forestry\ Cyclical\ Line\ Clearing}{KM's\ of\ Line\ Cleared}$$

Station Refurbishment MVA – Cost per Unit

This metric is newly proposed as part of this Application. This cost per unit metric will demonstrate how successful Hydro One is in delivering productivity improvement in its station refurbishment projects. This has been an area of interest in previous applications. As a result, the OEB directed Hydro One to complete a benchmarking study to support this Application. Hydro One has completed this study through Navigant and First Quartile, which can be found in Section 1.6 of the Distribution System Plan. Every station refurbishment project has a different scope of work that will change the total cost per project. As a result this metric should be viewed as a trend over a number of years. This metric will allow for benchmarking over time and will allow for cost per unit comparisons with other distributors, as well as inform management of the potential for improvements and aid in setting improvement targets.

$$= \frac{Total\ Cost\ of\ Station\ Refurbishment\ Program}{Total\ Stations\ MVARefurbished}$$

Note that the cost per MVA only considers projects which have a station MVA of less than 10 MVA. Including projects greater than 10 MVA would cause large cost fluctuations from year to year depending on how many were included due to the significantly lower per MVA cost. The smaller MVA category shows the most potential for improvement as it has the highest historical cost per MVA. This covers approximately 75% of the station refurbishment projects in 2018.

OM&A cost per Customer

This metric is newly proposed as part of this Application. Through the customer consultation process, residential and small business customers indicated that cost is their top priority and Large Customers indicated it was among their top priorities. This metric will help demonstrate how successful Hydro One is in delivering productivity improvement through OM&A reductions. This metric will also allow for benchmarking and cost comparison over time for Hydro One as well as comparisons with other comparable utilities.

$$= \frac{Total\ OM\&A}{Number\ of\ Customers}$$

OM&A Expense per km of Line

This metric is newly proposed as part of this Application. Through the customer consultation process, residential and small business customers indicated that cost is their top priority and Large Customers indicated it was among their top priorities. This metric will help demonstrate how successful Hydro One is in delivering productivity improvement through OM&A reductions. This metric will also allow for benchmarking and cost comparison over time for Hydro One as well as comparisons with other comparable utilities.

$$= \frac{Total\ OM\&A}{Number\ of\ line\ km's}$$

Witness: Michael Vels/Greg Kiraly/Darlene Bradley

Line Equipment Caused Interruptions

Hydro One began reporting this metric as part of its previous distribution rates application (EB-2013-0416) and proposes to continue reporting it as part of this Application. This metric is a count of the total number of outages caused by line equipment failures on an annual basis. Customers indicated, in general, that they value sustaining current reliability levels while managing rate impacts and effective cost management. This metric demonstrates the outcome of Hydro One's capital and maintenance programs in terms of line equipment caused outages. Benchmarking, over time, will demonstrate Hydro One's success in maintaining reliability and how effective Hydro One has been in the spending of resources on areas of the system that are in need.

$$= Line\ Equipment\ Caused\ Outages$$

Vegetation Caused Interruptions

Hydro One previously agreed to report this metric as part of EB-2013-0416. This metric is a count of the total number of vegetation-caused outages on line equipment on an annual basis. Visibility to the vegetation-caused outages allows for focus to be placed on those areas with less than optimal performance while ensuring Hydro One's on-cycle program for critical feeders is delivering good performance. Ultimately, the expected outcome and customer benefit of the vegetation management program is a reduction in vegetation-caused outages. This metric is directly impacted by the number of kilometres that were managed over many years and is not immediately impacted by the number of kilometres managed in the current or previous year. As a result this is a lagging indicator of the outcomes of the vegetation management program.

$$= Total\ Vegetation\ Caused\ Interruptions$$

Substation Caused Interruptions

Hydro One previously agreed to report this metric as part of EB-2013-0416. This metric is a count of the total number of substation equipment failure outages. Substation equipment failures often cause outages that are significantly longer in duration compared to vegetation-caused outages. This, in part, is due to limitations in transfer capabilities on Hydro One's network. Hydro One will manage these events by tracking these failures and adjusting the pace of substation refurbishment programs to align with customer expectations on system reliability. This metric is intended to measure the effectiveness of Hydro One's distribution station refurbishment program, through which Hydro One is endeavoring to reduce the cost per unit as demonstrated in the Station Refurbishment MVA Cost per Unit metric.

$$= Total\ Substation\ Caused\ Interruptions$$

SAIDI – Urban

This metric is newly proposed as part of this Application. Distinguishing between rural and urban reliability provides a better basis for benchmarking to other utilities and a higher quality metric for internal comparison. The Electricity Distributor Scorecard includes the Hydro One System Average Interruption Duration Index ("SAIDI") for the overall system. The SAIDI-Urban metric tracks the duration of interruptions for Hydro One's urban areas only and Hydro One is targeting to keep the performance of this measure consistent with historical results in the medium term, which aligns with customer expectations.

$$= \frac{Total\ Urban\ Customer\ Hours\ of\ Interruption}{Total\ Urban\ Customers\ Served}$$

Witness: Michael Vels/Greg Kiraly/Darlene Bradley

SAIFI – Urban

This metric is newly proposed as part of this Application. The Electricity Distributor Scorecard includes the Hydro One System Average Interruption Frequency Index ("SAIFI") for the overall system. The SAIFI – Urban metric tracks the frequency of interruptions for the urban areas only. Hydro One is targeting to keep the performance of this measure consistent with historical results in the medium term, which aligns with customer expectations.

$$= \frac{Total\ Urban\ Customer\ Interruptions}{Total\ Urban\ Customers\ Served}$$

SAIDI – Rural

This metric is newly proposed as part of this Application. The Electricity Distributor Scorecard includes the Hydro One SAIDI for the overall system. The SAIDI-Rural metric tracks the duration of interruptions for the rural areas only and Hydro One is targeting to keep the performance of this measure consistent with historical results in the medium term, which aligns with customer expectations.

$$= \frac{Total\ Rural\ Customer\ Hours\ of\ Interruption}{Total\ Rural\ Customers\ Served}$$

SAIFI – Rural

This metric is newly proposed as part of this Application. The Electricity Distributor Scorecard includes the Hydro One SAIFI for the overall system. The SAIFI-Rural metric tracks the frequency of interruptions for the rural areas only. Hydro One is targeting to keep the performance of this measure consistent with historical results in the medium term which aligns with customer expectations.

$$= \frac{Total\ Rural\ Customer\ Interruptions}{Total\ Rural\ Customers\ Served}$$

Large Customer Interruption Frequency Large Distribution Accounts (LDAs)

This metric is newly proposed as part of this Application. During the customer engagement process, Large Distribution Accounts ("LDA") informed Hydro One that their top priority was interruption frequency as even a short outage could have major financial impacts to their operations. Hydro One will track this new measure to address this specific reliability concern. The goal is to improve performance compared to historical results. This metric tracks the total number of sustained interruptions to all LDA customers connected to Hydro One.

$$= \frac{Total\ Interruptions\ for\ Large\ Distribution\ Customers}{Total\ Large\ Distribution\ Customers\ Served}$$

1.4.2 OUTCOME MEASURES: EB-2013-0416

In its previous distribution rate Application (EB-2013-0416), Hydro One submitted a list of outcome measures for future reporting. The measures and the results have been captured in Table 9 below. From the measures listed in the table below, Vegetation Caused Interruptions, Substation Caused Interruptions, Distribution Line Equipment Caused Interruptions, Handling of Unplanned Outages Satisfaction, and Residential and Small Business Satisfaction are metrics that Hydro One proposes to continue reporting in the future.

Table 9 – Outcome Measures from EB-2013-0416

Year	Actual		
	2014	2015	2016
Vegetation Caused Interruptions	6,540	6,944	7,674
Substation Caused Interruptions	158	141	103
Distribution Line Equipment Caused Interruptions	8,311	8,164	7,439
Number of Replaced Poles	11,179	11,837	12,355
Number of Pole Top Transformers with PCB Oil	NA	34	347
Residential and Small Business Satisfaction (%)	67%	70%	66%
Handling of Unplanned Outages Satisfaction (%)	75%	76%	83%
Estimated Bills Issued as % of Total Issued*	NA	4%	NA

***No longer measured, replace by bill accuracy measure**

Hydro One proposes to cease reporting the Number of Replaced Poles and Number of Pole Top Transformers with PCB Oil, as these measures are activity-based, which is not consistent with the intent of the RRF. Hydro One has replaced these measures with cost per unit metrics, which are consistent with the intention of the RRF in terms of demonstrating continuous productivity improvement. Hydro One proposes to cease reporting the Estimated Bills Issued as a % of Total Bills Issued as it believes this is adequately covered under the Billing Accuracy metric already reported on Hydro One's Electricity Distributor Scorecard.

1.4.2.1 RELIABILITY RESULTS

This section contains the reliability statistics for the historic period from 2012 to 2016.

Customer interruptions are analyzed and reported internally throughout the year. Interruption data is collected and recorded in the Distribution Operations and Maintenance Centre (part of Ontario Grid Control Centre) through communications with field staff involved in the interruption restoration. It is input into a database system called Outage Response Management System, which provides data for in-depth performance analysis to drive strategy and business investment decisions.

Interruption data is used to calculate the OEB reliability indices monthly, and results are reported internally. There is ongoing analysis of approximately 40,000 annual interruptions. Trends of frequency, duration, cause of interruptions, feeders, location, and other factors, are analyzed to allow prioritization of maintenance and capital programs on the distribution system.

Measures

Reliability is measured in terms of the duration of outages (SAIDI), the frequency of outages (SAIFI) and the average interruption time ("CAIDI"). The SAIDI, SAIFI and CAIDI statistics for the last five years are included in the tables below. For the distribution system as a whole, both SAIDI and SAIFI are reported with and without Loss of Supply ("LOS") and Force Majeure ("FM") events. In addition, details of the outages in terms of outage cause are also included. These statistics are reported including LOS and FM.

Duration of Interruptions (SAIDI)

The average numbers of hours that distribution customers served by Hydro One were without power in the year.

Frequency of Interruptions (SAIFI)

The average number of times that distribution customers served by Hydro One were interrupted in the year.

Average Interruption Time (CAIDI)

The average interruption duration (in hours) of Distribution customers who were interrupted. ($CAIDI = SAIDI \div SAIFI$)

The above reliability indices measure all interruptions caused by planned and unplanned interruptions of one minute or more.

Force Majeure

Hydro One deems a *force majeure* to have occurred when a storm or other event(s) causes the interruption of 10% of customers or more and causes a change in normal restoration business processes. All Hydro One customers interrupted throughout the duration of the event while normal restoration business processes are suspended are counted in the determination of the numerator of the percent interrupted. The denominator is the total number of customers served at the end of the month when the force majeure occurred. Details of all *force majeure* events that have occurred from 2012 to 2015 are provided below.

2012 Force Majeure Events

In 2012, there were four force majeure events.

- From March 2 to 4, an early spring storm that tracked up from Texas across Lake Huron and Georgian Bay to Lake Nipissing dragged a sharp cold front with strong winds from east to west across Southern Ontario. The winds reached up to 105 km/h along the Niagara Peninsula. This event affected 173,000 or about 14% of customers.
- From July 23 to 26, a strong lightning/thunderstorm, with hail and winds gusting up to 110 km/h moved through southeast Ontario and crossed over the Northeast areas. This storm caused widespread damage and affected 158,000 or about 13% of customers.
- From October 29 to 31, remnants of Hurricane Sandy, including winds moving up to 100 km/h, moved across Southern Ontario from the lower Great Lakes passing through Sarnia, Georgian Bay and the Niagara region. The combination of strong winds and residual leaves on trees caused power outages due to falling limbs and downed trees snapping power lines. This event affected 258,000 or about 21% of customers.
- From December 21 to 23, Environment Canada issued a weather warning for Eastern and Northern Ontario when up to 30 cm of snow fell in these regions. This winter storm caused severe damage to the distribution system; heavy wet snow and high winds caused trees to contact distribution lines. This event affected 147,000 or about 12% or customers.

These storms resulted in a contribution to the annual SAIDI of 3.9 hours and annual SAIFI of 0.6 interruptions per customer.

2013 Force Majeure Events

In 2013, there were seven force majeure events.

- From April 12 to 16, Environment Canada issued a weather warning when a slow moving low pressure system combined with Artic air to produce a mix of snow, rain, ice pellets and freezing rain over Southern Ontario. It laid down a blanket of 2 to 4 cm of snow and ice pellets in a band from Toronto to Lake Huron. The storm was accompanied by gusting winds of up to 65 km/h that caused downed tree limbs resulting in widespread power outages. This event affected 419,000 or about 34% of customers.
- From May 21 to 24, a tornado warning was issued by Environment Canada when two clusters of thunderstorms made their way through Southern Ontario. Both tornadoes were accompanied by intense lightning, hail, heavy downpours and wind gusts of up to 100 km/h that caused broken poles and downed trees. This event affected 147,000 or about 12% of customers.
- From May 31 to June 3, a line of thunderstorms with winds up to 90 km/h moved through Southern and Central Ontario. Hail, heavy rain and frequent lightning accompanying the storm caused widespread outages. This event affected 121,000 or about 10% of customers.
- From July 19 to 23, scattered thunderstorms moved over Northwestern Ontario accompanied by wind gusts of 90 km/hour, hail greater than 2 cm in diameter and downpours of up to 50 mm. At the same time, isolated thunderstorms moved over Southern and Central Ontario that were also accompanied with high winds, hail and heavy rain. Both incidents resulted in power interruptions to 434,000 or about 35% of customers.
- From November 1 to 3, a Colorado low pressure system bought rain and high winds to much of Southern Ontario. The winds reached speeds of up to 100 km/h in areas near Lake Erie and Lake Ontario. This event affected 315,000 or about 25% of customers.
- From November 17 to 19, another low pressure system from Colorado caused a strong cold front with heavy winds of up to 90 km/hour for much of South Western

and South Central Ontario. This event impacted both the distribution and transmission system and caused interruptions to 367,000 or about 28% of customers.

- From December 21 to 29, a low pressure system originating in Texas collided with a warm front causing up to 40 mm of freezing rain, snow and ice pellets to spread into Southern and Southwestern Ontario. As a result, ice accumulated on tree branches causing wide spread outages from downed trees. After the storm passed, light rain continued with extreme cold temperatures causing ice accumulation of up to 30 mm on surfaces and tree branches. The ice storm was followed by a windstorm of up to 55 km/hr that caused the ice-covered tree branches to contact distribution lines. This ice storm affected 585,000 or about 46% of customers.

The effect of these storms resulted in a contribution to the annual SAIDI of 20.1 hours and annual SAIFI of 1.8 interruptions per customer.

2014 Force Majeure Events

In 2014, there were two force majeure events.

- From September 5 to 6, a thunderstorm with large hail, high winds greater than 75 km/h, and heavy rain moved over Northwestern Ontario, Northeastern Ontario, Georgian Bay, Central Ontario, and Southern Ontario. This event affected a total of 137,000 or about 11% of customers.
- From November 24 to 25, strong wind storms passed through Southern Ontario with sustained wind speeds of 60 to 70 km/h. Gusts of 90 to 100 km/h passed through north of Lake Erie and Lake Ontario, Central Ontario, Grey /Bruce area and the GTA. Northeastern Ontario experienced freezing rain and snow with accumulations of up to 30 cm. This event affected a total of 238,000 or about 18% of customers.

The effect of these storms resulted in a contribution to the annual SAIDI of 2.0 hours and annual SAIFI of 0.3 interruptions per customer.

2015 Force Majeure Events

In 2015, there were three force majeure events.

- From August 1 to 4, a severe thunderstorm with wind speeds of up to 55 km/h, lightning and heavy downpours passed through Southern Ontario causing tree branches to fall on various portions of the power lines. This event caused interruptions to 144,000 or about 11% of customers.
- From November 6 to 9, a strong wind storm passed through Southwestern Ontario, Northwestern Ontario and Georgian Bay with wind speeds of up to 100 km/h. The high speed winds damaged poles and caused broken tree branches to fall on the lines causing power outages. This event caused interruptions to 277,000 or about 21% of customers.
- From December 24 to 26, a strong wind storm passed through Southwestern Ontario along the shores of Lake Huron with wind speeds of 70 to 90 km/h, damaging poles and causing tree branches to fall on various portions of the lines, which resulted in severe widespread outages. This event caused interruptions to 189,000 or about 14% of customers.

The effect of these storms resulted in a contribution to the annual SAIDI of 4.6 hours and annual SAIFI of 0.5 interruptions per customer.

2016 Force Majeure Events

In 2016, there were three force majeure events.

- From February 24 to 25, a winter snow storm with freezing rain and wind gusts between 60 and 80 km/h, travelled from Southern and Western Ontario towards Eastern Ontario. This late winter storm caused several power interruptions, affecting approximately 135,000 or 10% of Hydro One customers.
- From March 24 to 28, a severe ice storm with freezing rain and wind gusts of 70 to 90 km/h, hit Ontario causing wide-spread damage. Damage from the ice and wind, as well as fallen trees and branches caused several outages. In total this event impacted approximately 371,000 or 28% of Hydro One customers.
- From July 8 to 9, a severe thunderstorm moved across Ontario from the west to the east, causing extensive power interruptions. This event impacted approximately 143,000 or 11% of Hydro One customers.

Reliability Summary

The historical results for the past five years for SAIDI, SAIFI and CAIDI are provided below in Tables 10, 11, and 12, respectively. Results have been provided including and excluding both Loss of Supply (LOS) and Force Majeure (FM). From 2012 to 2016, reliability performance (SAIDI and SAIFI) excluding FM and LOS has generally been constant at 7.3 hours and 2.6 timers per customer per year. SAIDI and SAIFI for the overall system have generally deviated by less than 6% from the five-year average for the period. Force Majeure events increased these statistics, on average, by 90% for SAIDI and 25% for SAIFI. Loss of Supply also increased these statistics, on average, by 5% for SAIDI and 15% for SAIFI. As highlighted above, a number of storms in 2013 dramatically increased the frequency and duration of outages as can be seen in the tables and figures below. CAIDI is derived by dividing SAIDI by SAIFI. As a result, the performance of this measure is largely explained by the performance of SAIDI and SAIFI, as discussed above.

SAIDI and SAIFI by outage cause is provided in Tables 13 and 14. Tree contacts were the most common cause of outages for most years, followed by defective equipment.

Table 10 - Historical SAIDI Summary

Outage Cause	2012	2013	2014	2015	2016
Including LOS and Including FM	11.3	27.4	9.9	12.9	13.2
Including LOS and Excluding FM	7.5	7.3	7.9	8.3	8.3
Excluding LOS and Including FM	10.6	26.6	9.4	12.2	12.6
Excluding LOS and Excluding FM	7.0	6.9	7.4	7.6	7.8

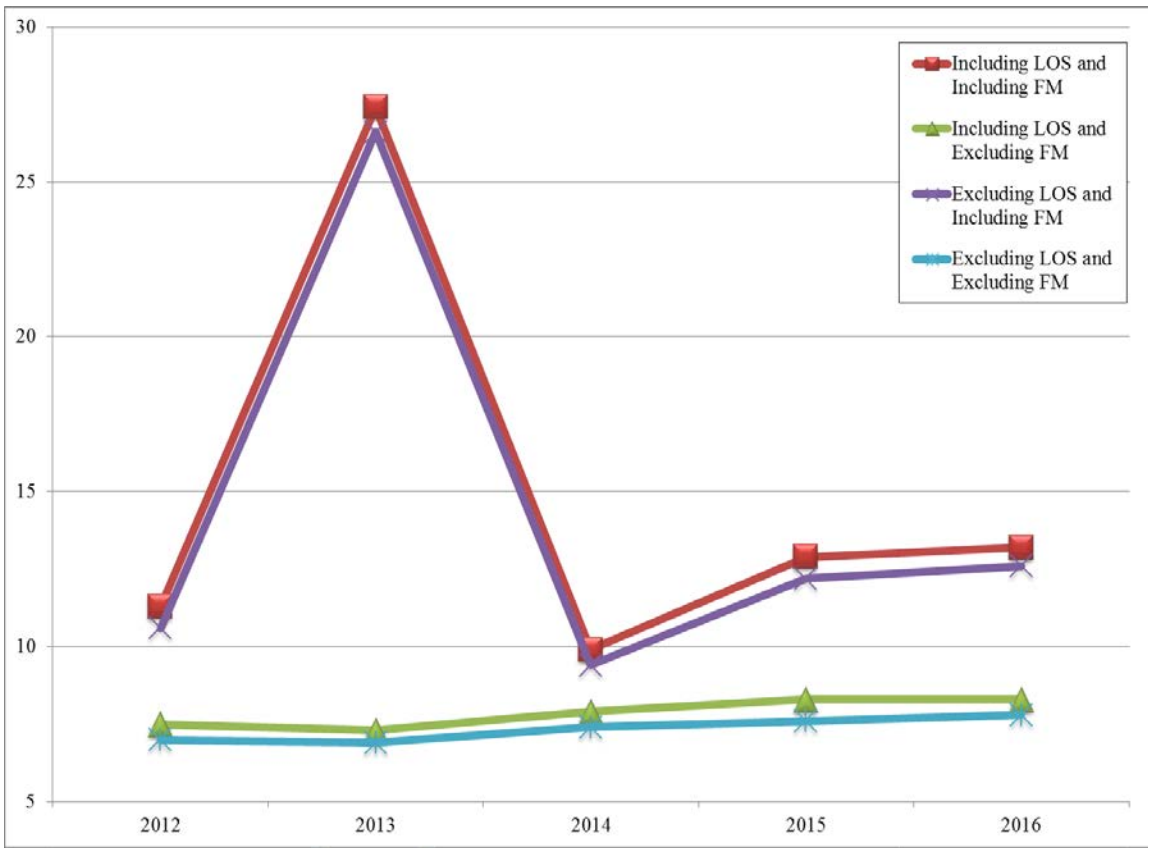

Figure 3 - Chart of Historical SAIDI

1 **Table 11 - Historical SAIFI Summary**

Outage Cause	2012	2013	2014	2015	2016
Including LOS and Including FM	3.7	4.6	3.6	3.6	3.4
Including LOS and Excluding FM	3.1	2.8	3.3	3.1	2.8
Excluding LOS and Including FM	3.2	4.2	3.0	3.1	2.9
Excluding LOS and Excluding FM	2.6	2.5	2.7	2.6	2.5

2

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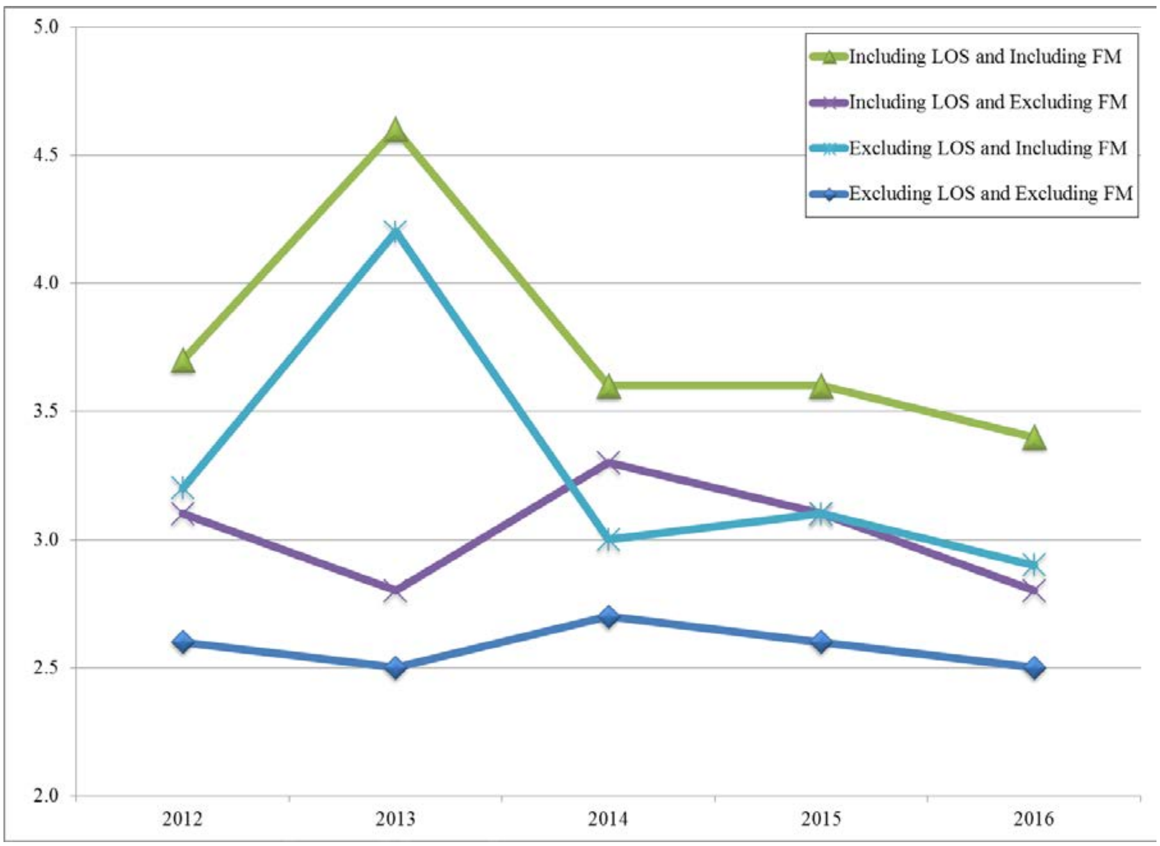

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5 **Figure 4 - Chart of Historical SAIFI**

Table 12 - Historical CAIDI Summary

Outage Cause	2012	2013	2014	2015	2016
Including LOS and Including FM	3.1	6.0	2.8	3.6	3.9
Including LOS and Excluding FM	2.4	2.6	2.4	2.7	3.0
Excluding LOS and Including FM	3.3	6.3	3.1	3.9	4.3
Excluding LOS and Excluding FM	2.7	2.8	2.7	2.9	3.1

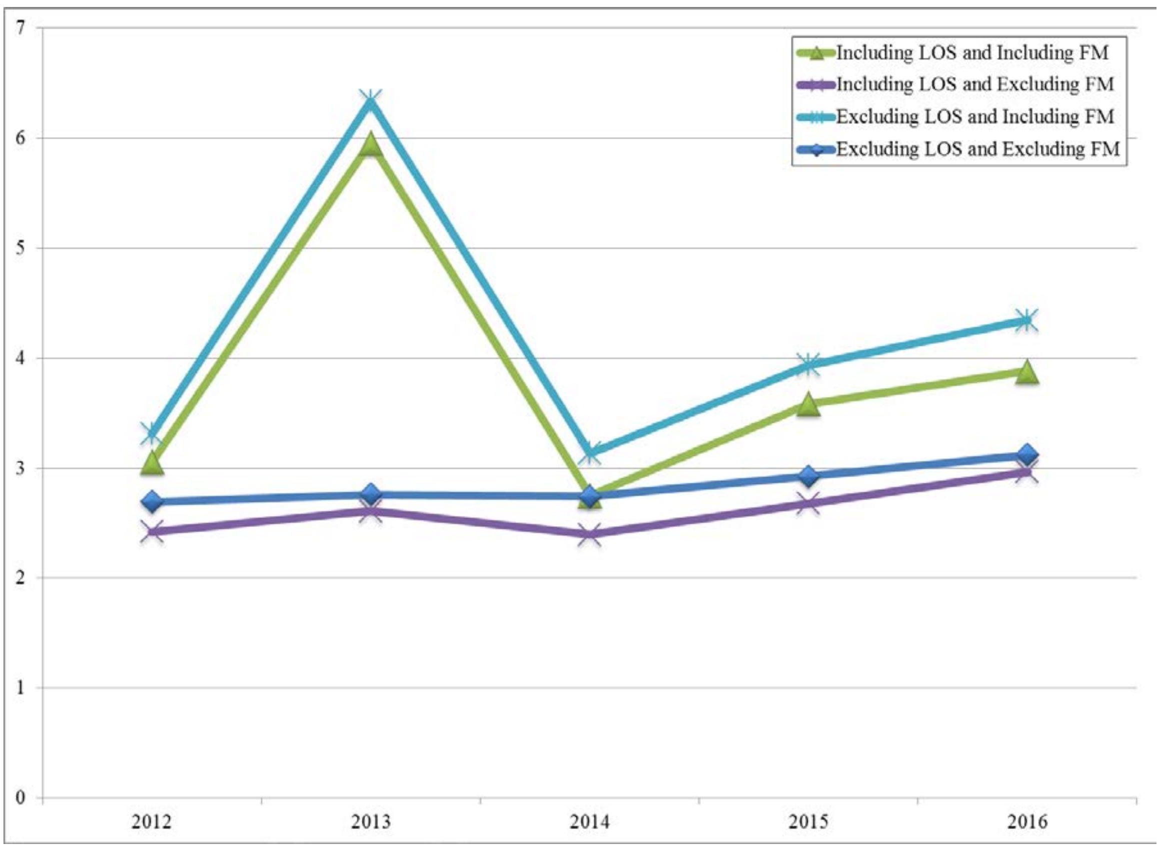


Figure 5 Chart of Historical CAIDI

Table 13 - SAIDI by Outage Cause

Outage Cause	2012	2013	2014	2015	2016
Adverse Environment	0.03	0.01	0.00	0.02	0.03
Defective Equipment	2.57	6.59	3.03	3.55	3.00
Foreign Interference	0.44	0.46	0.44	0.40	0.41
Human Element	0.04	0.11	0.08	0.08	0.05
Loss of Supply	0.72	0.96	0.56	0.72	0.61
Scheduled	1.41	1.53	1.48	1.43	1.48
Tree Contacts	4.24	14.67	3.36	5.53	6.17
Unknown/Other	1.84	3.09	0.96	1.20	1.43

Includes outages due to Loss of Supply and Force Majuere

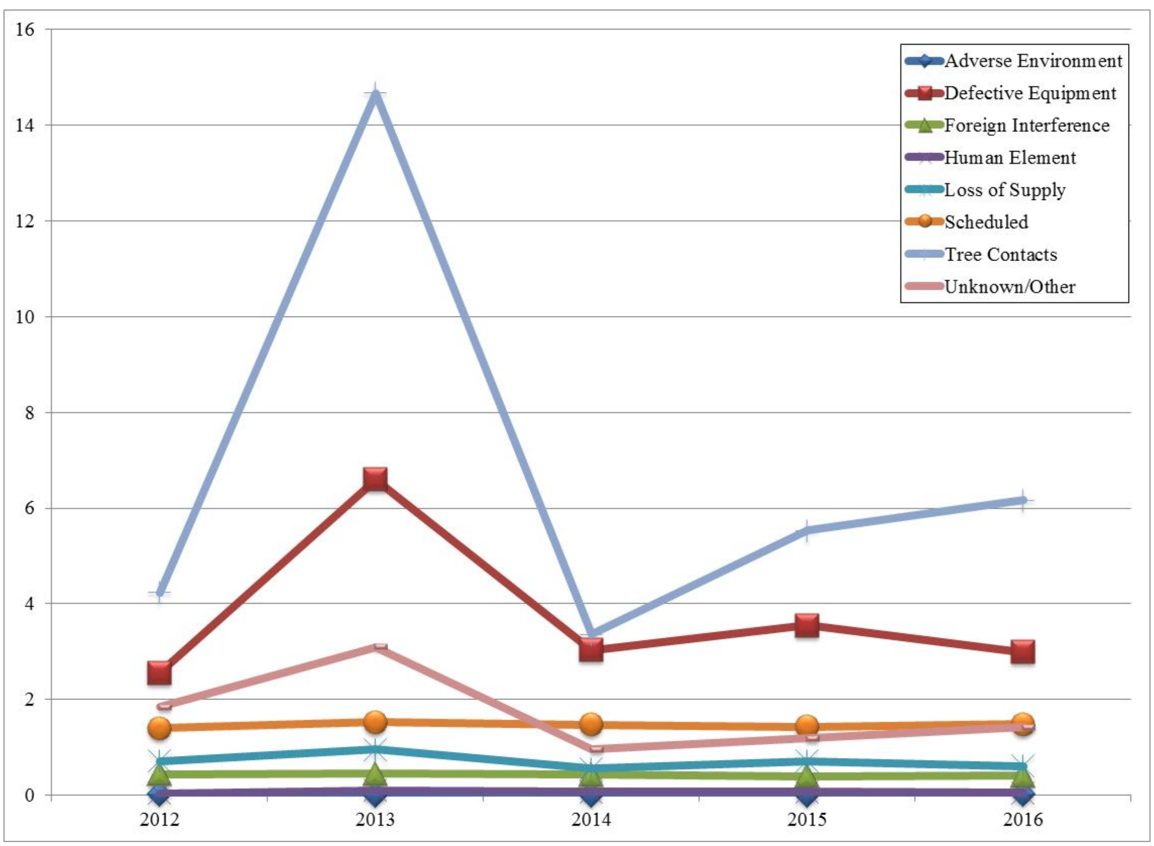


Figure 6 - Chart of SAIDI by Outage Cause

Witness: Michael Vels/Greg Kiraly/Darlene Bradley

Table 14 - SAIFI by Outage Cause

Outage Cause	2012	2013	2014	2015	2016
Adverse Environment	0.00	0.01	0.00	0.00	0.00
Defective Equipment	0.73	1.07	0.83	0.88	0.75
Foreign Interference	0.15	0.15	0.16	0.15	0.17
Human Element	0.03	0.06	0.08	0.07	0.04
Loss of Supply	0.54	0.40	0.62	0.50	0.49
Scheduled	0.62	0.68	0.63	0.60	0.57
Tree Contacts	0.80	1.36	0.62	0.78	0.81
Unknown/Other	0.81	0.90	0.61	0.60	0.57

Includes outages due to Loss of Supply and Force Majuere

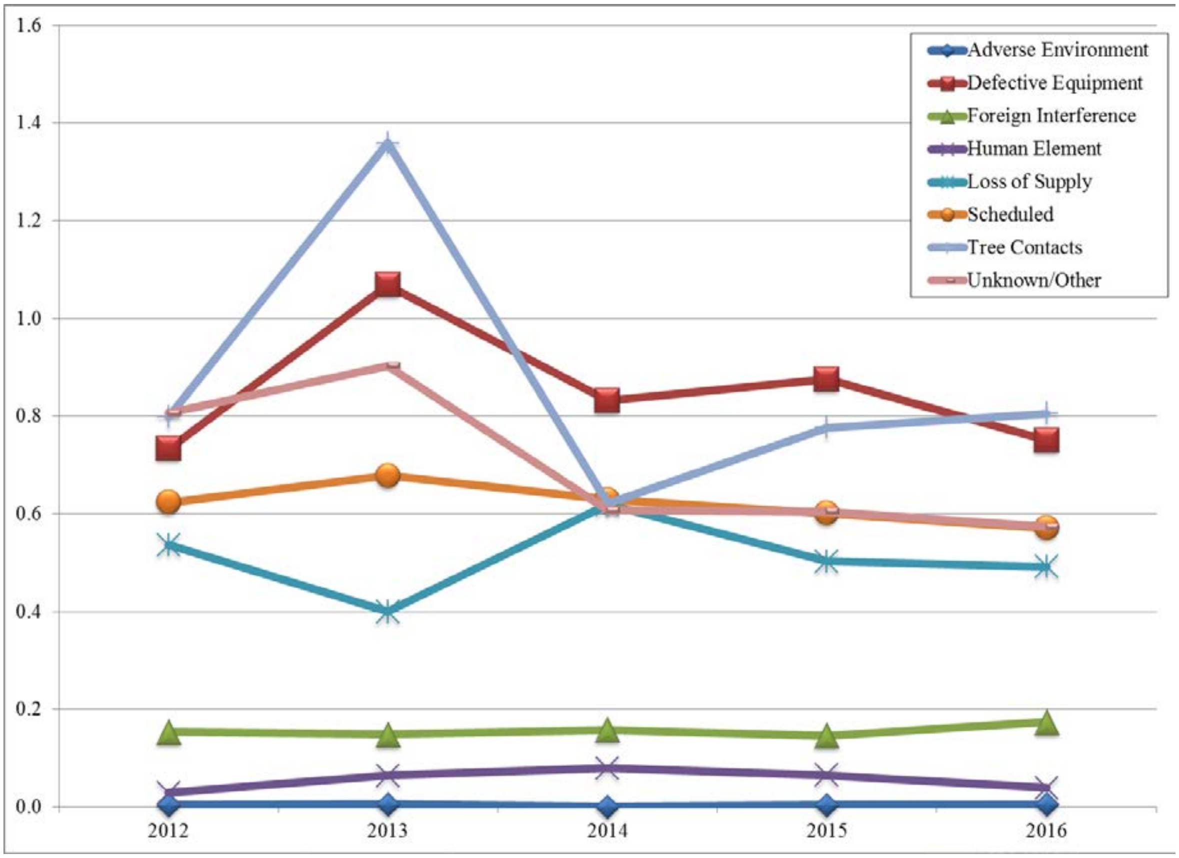


Figure 7 - Chart of SAIFI by Outage Cause

Table 15 – CAIDI* by Outage Cause

Outage Cause	2012	2013	2014	2015	2016
Adverse Environment	8.46	2.43	4.32	4.12	6.40
Defective Equipment	3.50	6.17	3.65	4.06	3.99
Foreign Interference	2.87	3.07	2.77	2.77	2.36
Human Element	1.47	1.67	0.96	1.20	1.36
Loss of Supply	1.34	2.41	0.90	1.43	1.25
Scheduled	2.26	2.25	2.35	2.38	2.60
Tree Contacts	5.31	10.79	5.42	7.12	7.66
Unknown/Other	2.29	3.43	1.59	1.98	2.49
Includes outages due to Loss of Supply and Force Majuere					

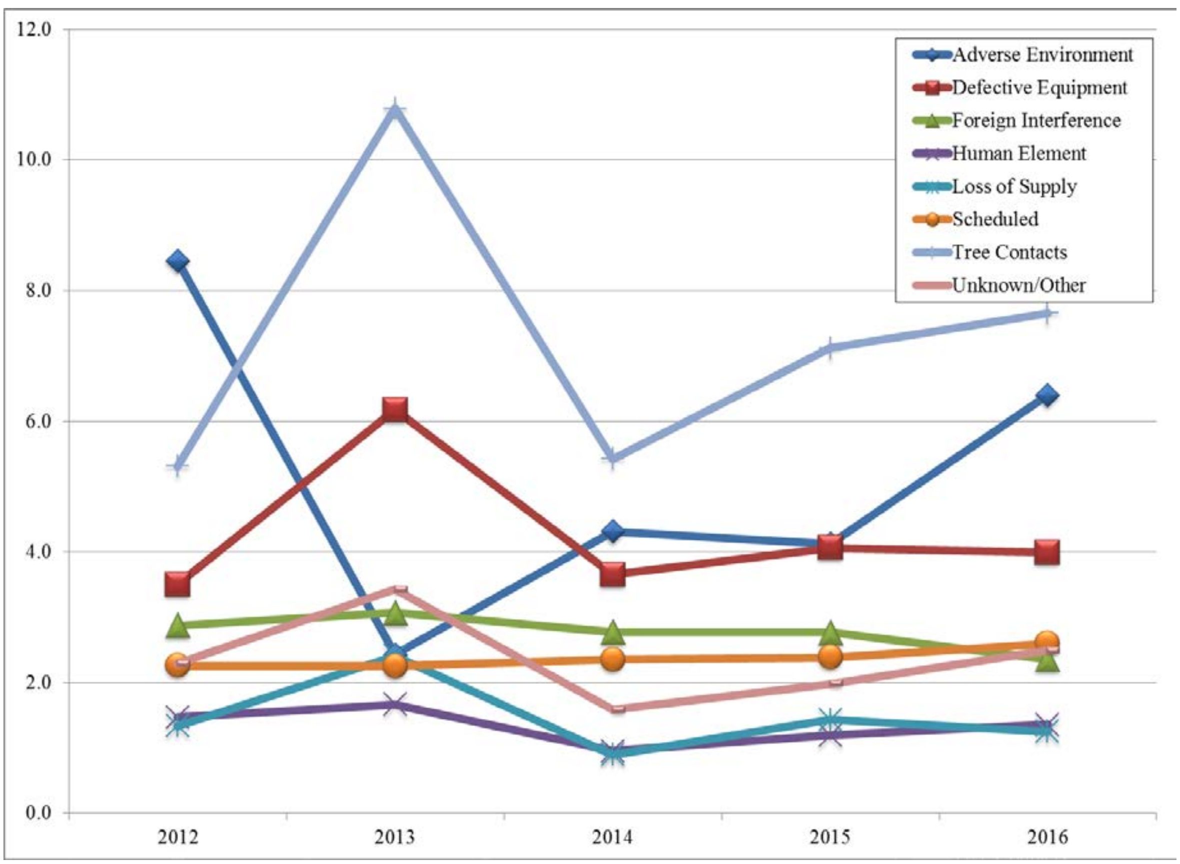


Figure 8 - Chart of CAIDI* by Outage Cause

** CAIDI provides the average outage duration that a typical customer would experience in any given year. CAIDI is equal to SAIDI divided by SAIFI.*

Witness: Michael Vels/Greg Kiraly/Darlene Bradley

1.4.3 (5.2.3 C) HOW THE PLAN REFLECTS PERFORMANCE MEASUREMENT AND OUTCOME MEASURES

The productivity and outcome measures discussed above are used to drive continuous improvement in asset management planning, work execution, and in customer oriented performance. The table below summarizes the alignment of Hydro One's performance measures with its Business Objectives and the corresponding RRF Outcomes.

1 **Table 16 - Hydro One Business Objective Alignment with Performance Measures**

RRF Outcomes	Hydro One Business Objectives	Performance Measures
Customer Focus Services are provided in a manner that responds to identified customer preferences	Improve current levels of customer satisfaction	• Handling Unplanned Outages Satisfaction % • Call Centre Customer Satisfaction % • My Account Customer Satisfaction % • New Residential/Small Business Services Connected on Time • Scheduled Appointments Met On Time • Telephone Calls Answered On Time • First Contact Resolution • Billing Accuracy • Customer Satisfaction Survey Results
	Engage with our customers consistently and proactively	• Used to inform outcomes
	Ensure our investment plan reflects our customers' needs and desired outcomes	• Used to inform outcomes
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives	Actively control and lower costs through OM&A and capital efficiencies	• Total Cost per Customer • Total Cost per km • OM&A per Customer • OM&A per km of Line • Pole Replacement –Cost per Unit • Vegetation Management – Cyclical Cost per km Line Clearing • Station Refurbishments – Cost per MVA

RRF Outcomes	Hydro One Business Objectives	Performance Measures
	Achieve and maintain employee engagement	• Drives company culture leading to improved Operational Effectiveness
	Drive towards achieving an injury -free workplace for employees and the public	• Drives company culture leading to improved Operational Effectiveness • Level of Public Awareness • Level of Compliance with Reg 22/04 • Number of General Public Incidents
	Provide reliability consistent with customer requirements.	• Average Number of Times that Power to a Customer is Interrupted • Average Number of Hours that Power to a Customer is Interrupted • Rural and Urban SAIFI • Rural and Urban SAIDI • Large Customer Interruption Frequency • Number of Substation Caused Interruptions • Number of Vegetation Caused Interruptions • Number of Line Equipment Caused Interruptions • Distribution System Plan Implementation Progress
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in	Ensure compliance with all codes, standards, and regulations	• Monitored by the applicable business unit(s)
	Partner in the economic success of Ontario	• Monitored by the applicable business unit(s)

RRF Outcomes	Hydro One Business Objectives	Performance Measures
legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Sustainably manage our environmental footprint	• Net cumulative energy savings • Renewable Generation Connection Impact Assessments completed on time • New Micro-embedded facilities connected on time
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Achieve the ROE allowed by the OEB	• Current Ratio (Current Assets/Current Liabilities) • Return on Equity (deemed) • Return on Equity (achieved) • Total Debt to Equity

INVESTMENTS DRIVING BUSINESS PERFORMANCE

The following sections demonstrate how the planned investments will enable Hydro One to achieve its Business Objectives and the corresponding targets set for its productivity and outcome measures. The impact of each material investment within the DSP is summarized below by OEB Performance Outcome and corresponding Hydro One Business Objectives.

1.4.3.1 CUSTOMER FOCUSED PROJECTS

The RRF Customer Focus Outcome aligns with Hydro One's business outcomes to improve current levels of customer satisfaction, engage with our customers consistently and proactively, and ensure our investment plan reflects the Company's customers' needs and desired outcomes. Hydro One has historically measured the degree to which it is meeting the objective of increasing customer satisfaction with the OEB scorecard measures:

- New Residential/Small Business Services Connected on Time;
- Scheduled Appointments Met on Time;
- Telephone Call Answered on Time;
- Customer Satisfaction Survey Results;
- First Contact Resolution; and
- Billing Accuracy.

In addition to the OEB scorecard measures, Hydro One has added four additional measures to better measure the level of customer satisfaction:

- Customer Satisfaction – Perception Survey %;
- Handling of Unplanned Outages Satisfaction;
- Call Centre Customer Satisfaction; and
- My Account Customer Satisfaction.

The following investments are targeted at improving customer satisfaction and are expected to positively impact the measures used to monitor customer satisfaction.

Worst Performing Feeders ISD SS 06.

This investment will facilitate capital works to improve performance on Hydro One's feeder performance outliers. The strategy for this investment is to focus on distribution system areas that are reliability performance outliers. This approach will keep system performance statistics stable and control capital costs by deferring other investments with less impact on performance. This investment is expected to increase the reliability of the distribution network for customers that have been experiencing poor performance by reducing the average frequency and duration of power outages. This is expected to positively impact the **Customer Satisfaction Survey Results**.

Customer Self Service Technology ISD GP 16.

This investment addresses the need to enhance customer experience through additional self-service tools and functionality. This investment is expected to improve customer engagement by providing a convenient mechanism through which customers can interact with Hydro One. This investment also provides customers with a streamlined online experience that allows them to better understand their bills. This investment is expected to improve the **My Account Customer Satisfaction** and **Customer Satisfaction Survey Results** measures.

Call Centre Technology ISD GP 28.

This investment addresses the need to replace a system that has reached end-of-life. The investment also addresses the need to improve customer satisfaction and operational efficiencies at the call centre, especially for commercial and Industrial customers. This investment is expected to positively impact the **Customer Satisfaction Survey Results, Call Centre Customer Satisfaction, First Contact Resolution** and **Telephone Call Answered on Time** measures.

Customer Service Billing Investments ISD GP 29.

This investment will provide Non-Energy Billing Integration and will also produce a redesigned and improved bill for customers in 2022. This investment is expected to improve **Customer Satisfaction Survey Results**.

Customer Data and Analytics ISD GP 32.

This investment will upgrade several customer analytic tools provided by Hydro One. This investment is required to improve customer satisfaction through implementing alerts and analytics functionality. This investment is expected to improve **Customer Satisfaction Survey Results** as customers would have access to tools to help them manage energy usage.

Customer Service Complaint Management Tool ISD GP 33.

This investment will integrate the Complaint Management System with our SAP Customer Information System. This investment addresses the need to improve customer satisfaction through better handling, tracking and resolution of customer complaints. This investment is expected to improve **Customer Satisfaction Survey Results** and **Call Centre Customer Satisfaction.**

Smart Meter Network Investments ISD GP 34.

This investment will upgrade several meter reading systems and processes. This investment will reduce the number of customers who receive estimated bills, thereby improving **Customer Satisfaction Survey Results** and support Hydro One's efforts to meet the Ontario Energy Board's **Bill Accuracy** target of 98%.

1.4.3.2 OPERATIONAL EFFECTIVENESS INVESTMENTS

The OEB Operational Effectiveness Outcome aligns with Hydro One's Business Objectives as illustrated in Table 16. The measures that align with these business objectives and the material investments that impact the performance of these measures are discussed below.

Actively Control and Lower Costs Through OM&A and Capital Efficiencies

Hydro One has historically measured the degree to which it is meeting the objective to actively control and lower costs through OM&A and capital efficiencies with the following productivity measures:

- Cost/customer
- Cost/km
- OM&A/customer
- OM&A/km

- Pole replacement -unit cost
- Vegetation Management - unit cost
- Station refurbishments transformer bank- unit cost

The following investments are intended to actively control and lower costs through OM&A and capital efficiency gains and are expected to positively impact the measures used to monitor cost efficiency.

Remote Disconnection / Reconnection Program ISD SS 01.

The investment will result in the installation of meters with Remote Disconnect/Reconnect ("RDR") capabilities. Installing RDR capable meters will reduce the number of truck rolls required for disconnection and reconnection of service, required for customer needs such as move in and move out. Over the period 2018to 2022 planning period, 55,625 RDR capable meters will be installed.

Collection Enhancements ISD GP 31

This investment will enhance Hydro One's collections processes and functionality and implement pre-paid metering. This investment will improve collections and reduce bad debt expense at Hydro One leading to an increase in operational efficiency.

Corporate Performance Reporting ISD GP 07

The new Corporate Performance Reporting ("CPR") application will replace third-party software that requires support from an external vendor. The new application will be internally supported leading to reduced vendor costs. It will also be integrated with Hydro One's SAP system allowing for greater flexibility to meet reporting requirements.

Transport and Work Equipment (TWE) Capital Requirements ISD GP 01

This investment will replace transport and work equipment that is deemed to be at the end of its expected service life resulting in an optimal fleet composition that meets industry standards. This investment will maintain or improve operational efficiency by minimizing maintenance costs, shortening vehicle downtime, and increasing fleet availability.

Work Management & Mobility ISD GP 10

This investment will result in a refresh of the mobile technology used by Hydro One Distribution. The investment will eliminate or automate a significant amount of manual work and improve workforce effectiveness through better scheduling. In addition to the overall cost measures, this investment will have a positive impact on several distinct measures including pole replacement unit cost, vegetation management unit cost and station refurbishments – cost per transformer bank.

Business Process Consolidation ISD GP 12

This investment will allow the expanded use of the SAP Business Planning and Consolidation tool to add functionality such as integrated investment planning, business planning and forecasting capability. The added functionality will improve accountability and planning accuracy, shorten cycle times and allow for period books to be closed faster. This investment will yield operational and process efficiencies and improved decision-making capabilities.

Human Resource (HR) & Pay Related Technology Investments ISD GP 13

This investment will implement various process and tool enhancements to Hydro One's HR and Pay operations. This investment will improve efficiency/productivity in the HR & Pay area. These tool and process enhancements will increase operational efficiency.

Warehouse Scanning Device Replacement ISD GP 14

This investment will upgrade the bar coding devices used to manage warehouse inventory. This investment will enable Hydro One to monitor its inventory more efficiently, accurately and at reduced cost, all outcomes that increase operational efficiency.

SAP Treasury ISD GP 15

This investment will replace the Treasury system that has reached the end of its useful life and will no longer be supported by the vendor. The investment will implement the SAP Treasury & Risk Management System. Integration with enterprise SAP self-service tools results in savings attributable to better processes and more timely financial data. This investment improves business performance through using standard SAP automated processes for cash management, reducing manual entries for wire and ETF payments, and providing timely updates of bank data and transactions.

S4 HANA for Finance and Enterprise Asset Management ISD GP 17

This investment involves the replacement the SAP enterprise reporting platform with a new system, S4 HANA for Finance and Enterprise Asset Management. Implementation of the new system will improve decision-making with real time reporting, process simplification, better data quality, and a more effective interface. The new system will also increase processing speed and system performance. This investment will yield operational efficiencies.

Station Spare Transformer Purchases, ISD SR 03

This investment will result in the purchase of spare transformers for distribution stations as needed to support the in-service population. Operating with current proposed Mobile Unit Substation (MUS) fleet size requires spare transformers to be available to eliminate the 6 to 12 month transformer lead time. Hydro One has optimized its inventory of spare transformers required by moving toward a more standardized fleet of in-service transformer banks. This investment will also lower cost by reducing the need for expansion of the MUS fleet that would otherwise be necessary to support long transformer lead times.

Manage Public Safety Risk

Managing Public Safety Risk involves assessing the risks to the public from Hydro One's business operations, assessing the probability of an event and the severity of that event, and assessing the costs to mitigate identified risks. The following investments are expected to have a positive impact on Hydro One's Business Objective to manage public safety risk and are expected to drive improvement in the measures used to monitor this objective.

Station Security Upgrades, ISD GP 24

This investment provides for the installation of upgraded security measures at distribution stations to mitigate break and enter occurrences and prevent thieves from stealing copper grounds and neutral conductors. This investment is expected to improve public safety by mitigating the public's exposure to compromised grounding systems and station perimeters, positively impacting the number of general public incidents. In addition, this investment is expected to reduce maintenance costs associated with repairing the damage caused to distribution stations as a result of break and enters.

Component Replacement – Submarine Cable ISD SR 11

This investment will replace or refurbish submarine cables that are damaged or exposed at the shoreline and present a risk to public safety and are at an increased risk of failure. The public expects Hydro One to manage these safety risks. This investment is expected to mitigate public safety risks posed by damaged submarine cables and positively impact number of general public incidents.

Providing Reliability Consistent with Customer Requirements

Most of Hydro One's customers expect the level of system reliability to be maintained while large customers expressed a desire for improved reliability and a reduction in the frequency of outages. Hydro One will measure the degree to which it is meeting the objective of providing reliability consistent with customer requirements with the following measures:

- Substation-caused interruptions;
- Vegetation-caused interruptions;
- line equipment-caused interruptions;
- OEB Scorecard SAIDI;
- OEB Scorecard SAIFI;
- Rural SAIFI;
- Rural SAIDI;
- Urban SAIFI; and
- Urban SAIDI.

The following investments are targeted at providing reliability consistent with customer expectations and are expected to positively impact the measures used to monitor Hydro One's reliability performance.

Distribution Station Component Planned Replacements Program ISD SR 04

This investment replaces station equipment components that are at the end of their useful life and are not otherwise planned to be addressed by the station refurbishment program. By replacing these components before they fail, this investment will help maintain the substation-caused interruptions measure.

Distribution Station Recloser Upgrades ISD SR 05

This investment, which is part of an ongoing program, proactively installs new station reclosers at feeders where the existing protective device has become insufficient to meet electrical requirements. The new reclosers have lower maintenance costs, can be monitored and controlled remotely and have a longer service life. The quantity and funding for recloser upgrades is expected to be in line with historical levels to help maintain substation-caused interruptions within the historical range.

Distribution Station Refurbishments ISD SR 06

This investment, which is part of an ongoing program, replaces or refurbishes distribution stations at the end of their useful life before they fail. This investment is expected to help maintain substation-caused interruptions within the historical range.

Pole Replacement Program ISD SR 09

This program addresses replacement of wood poles and associated hardware that are at the end of their useful life. By replacing these poles before they fail, this investment is expected to maintain line equipment-caused outages within the historical range.

Distribution Line Component Replacements ISD SR 10

Hydro One performs assessments to identify distribution line components that are near the end of their useful life. This program addresses replacement of those line components. By replacing these components before they fail, this investment is expected to maintain line equipment-caused interruptions within the historical range.

Reliability Improvements ISD SS 03

This investment provides targeted reliability improvements in areas where customers have expressed concerns about the performance of the existing distribution network. Based on the currently identified projects targeted for reliability improvement in this DSP, overall SAIDI and SAIFI numbers are not expected to change materially from the historical range due to the local and limited size of these projects relative to Hydro One's system. However, this investment is expected to positively impact the Large Customer Interruption Frequency measure.

Worst Performing Feeders ISD SS 06

The strategy for this investment is to focus on distribution system areas that are reliability performance outliers and defer investments with less impact on performance. This investment aligns with customer preferences to sustain reliability and positively impact costs. This investment is expected to positively impact reliability of the feeder performance outliers and sustain the proposed SAIDI and SAIFI measures.

1.4.3.3 PUBLIC POLICY RESPONSIVENESS INVESTMENTS

The OEB Public Policy Responsiveness Outcome aligns with Hydro One's Business Objectives to ensure compliance with all codes, standards and regulations, partner in the economic success of Ontario and sustainably manage our environmental footprint. A significant portion of Hydro One's material investments are non-discretionary and are driven by the need to adhere to these business objectives. These investments do not directly align with specific performance measures but are critical to Hydro One's compliance with OEB Public Policy Responsiveness outcomes and the Company's corresponding Business Objectives. These non-discretionary investments are listed below.

- Life Cycle Optimization & Operational Efficiency Projects ISD SR 13;
- Distribution Lines Trouble Calls & Storm Damage Response Program ISD SR 07;
- AMI Network Expansion ISD SA 03;
- System Upgrades Driven by Load Growth ISD SS 02;
- Joint Use and Line Relocation Program ISD SA 01;
- Meter Inventory Sustainment ISD SA 02;
- AMI Hardware Refresh ISD SR 14;
- New Load Connections, Upgrades and Cancellations and Metering ISD SA 04;
- Generation Connections ISD SA 05;
- Enterprise Content Management (ECM) - Phase C ISD GP 09;
- Customer Service Regulatory Changes and Pricing Options ISD GP 30;
- Distribution Line PCB Equipment Replacement Program ISD SR 08;
- Leamington TS Capital Contribution ISD GP 25;
- Hanmer TS Capital Contribution ISD GP 26;
- Enfield TS Capital Contribution ISD GP 27;
- Demand Investments ISD SS 04;
- Distribution Station Demand Program ISD SR 01; and
- Distribution System Modifications ISD SS 05.

Details on each of the investments listed are available in the corresponding ISD in Section 3.8.

1.4.4 ATTACHMENTS: PERFORMANCE MEASURES AND OUTCOME MEASURES

Attachment	Name
1	Productivity Reporting Governance Document

Productivity Reporting Governance Document

February 17th, 2017

Contents

Productivity Reporting at Hydro One 1
Definitions 1
Performance Outcomes 2
Performance Scorecards 2
Performance Metrics 3
Authorities & Accountabilities 3
Deliverables and Stakeholders 4

Productivity Reporting at Hydro One

Hydro One's goal is to be a best-in-class customer-centric commercial utility with a culture of continuous improvement and excellence in execution. Successful execution and performance measurement are critical to achieving this goal and will allow Hydro One to deliver incremental Value to customers in the coming years.

Hydro One will track and document the collective effort of all organizations to improve the Value provided to customers for program spending. The reporting of these efforts will drive increased accountability for management to achieve Productivity gains and will provide a transparent view for the regulator and our customers that Hydro One has adopted a culture of continuous improvement.

Definitions

Value

Value for the purposes of Productivity reporting can be defined as the service level provided to customers relative to the cost they pay through electricity rates. Customers assign different levels of importance to the services provided by Hydro One but it is clear through customer engagement that customers place the most Value in having a low cost electricity distributor without sacrificing performance in maintaining a safe, reliable electricity system. Creating Value for customer's means improving the service level provided while lowering the relative cost to provide those services.

Productivity

Productivity gains are the result of improved planning or execution of work that increases Value to the customer. This Value can be measured through output/input metrics which often are based on the cost per unit of output in a given work program. These metrics are measured over time to show the increasing Value to customers for program spending. Savings from new technologies and process innovations will naturally impact these metrics as they reduce costs to the customer while providing consistent or improved service levels. Productivity is quantifiable and can be measured through dollars or other numerical units.

Savings

There are many initiatives in place or under development that specifically target cost reductions in work programs and corporate support services. These Savings are tracked and reported to gauge the success of the initiatives and to find new ways to build upon their success. However, ultimately Productivity will be measured using metrics that demonstrate increasing Value to the customer rather than total Savings achieved.

Avoided Cost

Through Hydro One's business planning process, future cost increases can be identified in time to develop a strategy to mitigate or eliminate the increase. Avoided Costs are by their nature difficult to quantify as the conditions that would have caused the cost increase were prevented from occurring. These avoided costs will not be included in Savings tracking or Productivity reporting, but do impact the Value being generated for customers.

Performance Outcomes

In order to ensure that Hydro One is achieving its Productivity and cost efficiency goals it has aligned its planning, execution and reporting functions around performance outcomes. These outcomes are based upon the Renewed Regulatory Framework (RRF) that the Ontario Energy Board (OEB) has implemented for use in both Transmission and Distribution regulatory proceedings. The RRF outcomes are designed to provide additional transparency into the performance of Hydro One in these four areas:

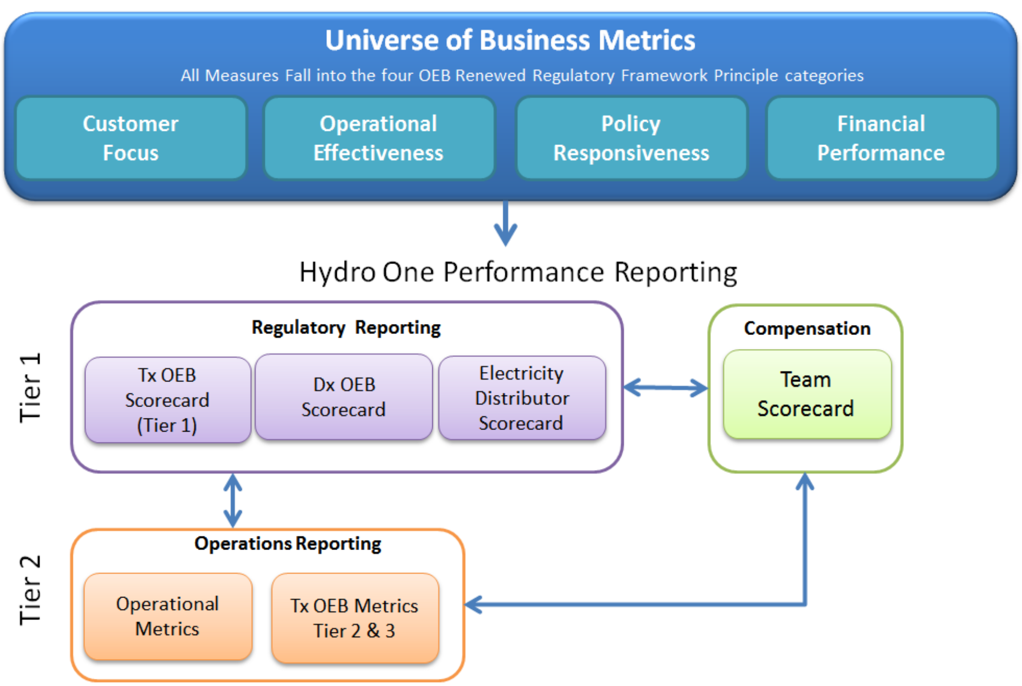
1. Customer Focus,
2. Operational Effectiveness,
3. Policy Responsiveness, and
4. Financial Performance

A direct correlation can be drawn between Hydro One's business objectives and the RRF performance outcomes.

Performance Scorecards

Hydro One primarily reports its performance through regulatory scorecards and the Team Scorecard which is used for the Short Term Incentive Plan award. These four scorecards comprise the Tier 1 scorecards that are reported internally and externally. The Tier 2 scorecards were designed for operational reporting to help managers effectively run the business. The measures on these scorecards often overlap, and at a minimum support the achievement of the Tier 1 goals, to ensure management at all levels are working towards the same goals.

The illustration below provides a view of the relationship between the RRF principles, the universe of business metrics and the scorecards used for reporting.



Performance Metrics

The regulatory scorecards and the Team Scorecard are composed of metrics that are designed to demonstrate the increasing Value to customers for program spending. The most evident of these are the cost per unit metrics that aim to reduce the cost of putting a standardized unit into service. Cost per unit metrics are impacted by both a reduction in costs (inputs) as well as the total number of units put into service (outputs). Increasing the number of units put into service will provide Value to the customer by improving service levels such as reliability. By showing an improvement in these metrics over time, Hydro One is demonstrating that it is providing an improved service level relative to the cost of providing the service.

For example cost per unit for the Wood Pole Replacement program is a metric where Value for the customer can be generated by maintaining service through reliability while reducing the cost of the pole through labour and material efficiencies. If the same standardized unit of pole is being replaced at a lower total cost then the customer will realize the Value through their electricity rates.

The reliability and customer service metrics on the scorecards are examples of metrics that are focused on the service level side of the equation (outputs). Since these service levels are very broad and cover many work programs and customer service efforts, they must be measured relative to other cost metrics (inputs) included on the scorecards such as OM&A per customer and OM&A per line km. These high level metrics will show the trend in spending that when viewed with the service level performance metrics will illustrate the Value that customers are receiving relative to spending over time.

Authorities & Accountabilities

Lines of Business

Each line of business is accountable for developing a Productivity strategy including targets and forecasts for the business planning period. This strategy should be aligned with Hydro One's business objectives and will focus on providing additional Value to customers. Lines of business will be responsible for executing their Productivity strategy and achieving the targets that are imbedded in the Productivity plan.

Business Planning

Business Planning will support LOB's in designing Productivity metrics to measure the effectiveness of the organizations Productivity strategy. The Productivity team will also review the data governance and reporting methodology for all metrics used in reporting (both internal and external).

Finance

Finance is the owner of the Team Scorecard and is accountable for reporting the results based on the internal reporting schedule.

Regulatory

Regulatory is the owner of the regulatory scorecards and is accountable for reporting based OEB requirements.

Deliverables and Stakeholders

Productivity reporting has two primary customers, including the Executive Leadership Team and the OEB. The OEB requires annual reporting to ensure performance levels are being maintained as well as for rate setting purposes during regulatory proceedings. The Executive Leadership Team requires monthly and quarterly reporting in order to successfully manage the business and achieve the business objectives.

Scorecard	Ontario Energy Board	Executive Leadership Team	Operations Managers
Regulatory			
Tx OEB – Tier 1	Annual	Quarterly	Monthly
Dx OEB	Annual	Quarterly	Monthly
Electricity Distributor Scorecard	Annual	Quarterly	Monthly
Compensation			
Team Scorecard	Upon Request	Monthly	Monthly
Operational Reporting			
Tx OEB – Tier 2 & 3	Not Provided	Quarterly	Monthly
Operational Reporting	Not Provided	Not Provided	Monthly

TAB 2

Attachment 1 – System Upgrades Driven by Load Growth

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-1	Cumberland DS F4 Development	Extend the lightly loaded F4 feeder from Cumberland DS to meet with the more heavily loaded F2.	Provide a loop feed for the Cumberland urban load area and meet future load needs.	1.2	2018
LG-2	Devlin DS F1 3 Phase Upgrade	Upgrade 3 km of two-phase and 1.5 km of single-phase line to three-phase along Highway 613.	Address single phase line loading above Planning Guidelines.	1.0	2018
LG-3	Kleinburg TS M6 Mayfield Rd Line Extension	Extend 27.6 kV along Mayfield Road, for approximately 4 km, from Airport Rd to Dixie Road.	Improve supply efficiency and reliability and provide capability to supply future loads along Mayfield Road in the Town of Bolton.	1.0	2018
LG-4	Orangeville TS M3 - Mayfield West Line Extension	Extend 44 kV feeder from Chinguacousy Rd, east along Old School Road, for approximately 6 km.	Introduction of 44kV to the Mayfield West area, to facilitate connection of anticipated industrial loads, and to construct a future Old School Road DS.	1.8	2018
LG-5	New Bradford North DS	Construct new 44-27.6 kV DS, as well as associated feeders.	To meet forecast residential and commercial load growth in the Town of Bradford West Gwillimbury.	5.0	2018-2019
LG-6	Caledonia TS M3 Extension	Convert 7.5 km of 4.16 kV line to 27.6kV and transfer load from Jarvis TS M3 to Caledonia TS M3.	Relieve overloaded step-downs and improve reliability to Six Nations.	1.1	2018-2019
LG-7	Alfred DS F2 Feeder Upgrades	Upgrade 6 km of single-phase line to three-phase, balance loads between phases, and between F1 and F2 feeders.	Single phase line section loaded above planning guideline.	2.4	2018-2019
LG-8	Cameron DS Feeder Improvements	Construct new F2 feeder out of Cameron DS and upgrade existing single phase line to three phase along Monarch Road and Hwy 35.	To meet forecast residential load growth in west part of the Town of Lindsay.	1.4	2018-2019
LG-9	Armitage TS M22 Extension	Extend M22 feeder by double circuit with existing M12 feeder, for approximately 6 km. Transfer Wesley DS from M12 to M22.	Provide load relief to Armitage TS feeder M12 which is loaded beyond planning guidelines.	2.0	2018-2019

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-10	City of Owen Sound Tie-Line Reinforcement	Construct new 4.16 kV tie-lines between 24th St West DS and 2nd Ave West DS, and between 6th Street East DS, and 2nd Ave East DS.	To provide loop feeds for single-contingency back up of DS transformers which do not have MUS facilities.	1.3	2018-2019
LG-11	Enfield TS Feeder Development	Construct two new 44 kV feeders out of Enfield TS consisting of 18 km of new feeder line.	To meet forecast load growth in Durham Region.	7.6	2018-2019
LG-12	Grand Bend DS F3 Voltage Conversion	Convert existing 8.32 kV feeder to 27.6 kV and connect to Grand Bend East DS F2 feeder.	To address substandard voltage being experienced by customers along the Lake Huron shoreline south of Grand Bend.	2.4	2018-2019
LG-13	Kirkland Lake Voltage Conversion – Part 1	Rebuild Goodfish DS and replace 44-4.16 kV transformer with a 44-12.5 kV unit. Convert Goodfish DS F8, F9, F10 feeders from 4.16 kV to 12.5 kV.	Meet future load needs in the Town of Kirkland Lake and eliminate obsolete metalclad switchgear at Goodfish DS.	4.8	2018-2019
LG-14	Leamington TS Feeder Development	Build 8 new 27.6 kV feeders from Leamington TS, transfer load and DG from Kingsville to Leamington TS, and partial 8.32 kV DS conversion to 27.6 kV.	Meet future load needs in the towns of Kingsville and Leamington consistent with Supply to Essex County Transmission Reinforcement (SECTR) work.	3.7	2018-2019
LG-15	Manotick DS Feeder Development	Extend new F3 feeder to off-load existing F1 feeder and to connect to new residential subdivisions.	To connect new residential subdivisions in Manotick to new F3 feeder.	2.6	2018-2019
LG-16	Stouffville 10th Line DS New T3 & Feeder	Construct new DS with 2 x 44 - 27.6 kV and 1 x 44 - 8.32 kV transformer.	Replace existing end-of-life 8.32 kV T1 station assets and add more capacity to meet the load growth in the Town of Stouffville.	6.6	2018-2019
LG-17	Town of Shelburne Voltage Conversion	Convert 4.16 kV feeders to 8.32 kV and rebuild Shelburne DS as a single-transformer station, 44-8.32kV. Remove existing T1 and T2 transformers.	Increase transformer and feeder capacity at Shelburne DS to meet forecast load growth.	8.4	2018-2020

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-18	Twelve Mile Bay DS - New Station & Feeders	Construct a new 44-12.5 kV station including 1 km of new 44 kV line with 12.5 kV underbuild, and install 11 km of new three-phase submarine cable in Georgian Bay to connect the new station to the Honey Harbour DS F1 feeder.	Provide load relief to Foots Bay DS which is loaded above its PLL, and to the Honey Harbour DS F1 feeder which does not meet system protection requirements.	4.0	2018-2019
LG-19	Beckwith DS F3 Feeder Development	Extend new Beckwith DS F3 feeder to off-load F1 and T1 transformer.	Relieve T1 overloading and create a three-phase loop feed for urban customers.	1.8	2019
LG-20	Crilly DS Replacement and Transformer Upgrade	Construct new Crilly DS 2 km from existing DS site. New Crilly DS will be supplied from Hydro One 115 kV circuit.	Address overloaded transformer and eliminate non-standard supply from privately owned generating station bus.	6.7	2019
LG-21	Kirkland Lake Voltage Conversion- Part 2	Replace 44-4.16 kV transformer at Woods DS with a 44-12.5 kV unit. Convert Woods DS F5, F6, F7 feeders from 4.16 kV to 12.5 kV.	To meet future load needs in the Town of Kirkland Lake.	2.0	2019
LG-22	Manotick DS F3 New Feeder	Add new feeder position and underground egress to connect new F3 Feeder	To meet forecast residential load growth in the Village of Manotick	1.9	2019
LG-23	Margach DS F3 Voltage Conversion - SW676	Extend Keewatin DS feeder F2 for 3.5 km to off-load part of the Margach DS F1 load onto Keewatin DS F2.	Provide load relief to overloaded step-down transformer.	1.4	2019
LG-24	Muskoka TS M5 x M1 Feeder Tie	Extend the Muskoka TS M5 feeder for 14 km from Ullswater DS to the village of Rosseau by overbuilding existing 12.5 kV feeders with 44 kV.	To facilitate off-loading Parry Sound TS through a load transfer to the Muskoka TS M1 feeder and to create a 44 kV loop feed around Lake Rosseau.	5.3	2019
LG-25	Rockland DS T2 Transformer	Install a second transformer at Rockland DS.	Provide load relief to existing T1 transformer and meet forecast load growth.	2.3	2019
LG-26	Barrie TS - Construct New Feeders	Construct 8 km of New 2-circuit 44 kV Line from Barrie TS to Salem Road.	To meet forecast load needs of InnPower embedded LDC.	2.6	2019-2020
LG-27	Caledonia TS New Feeders	Construct 6 km of new 27.6 kV feeders from Caledonia TS.	Relieve Existing Feeders which are loaded above planning guideline.	4.3	2019-2020

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-28	Dundas TS #2 New Feeders	Construct 2.5 km of new feeders from Dundas TS#2. Construction will be done across the Niagara Escarpment and through a subdivision.	To provide load relieve to Dundas TS T1/T2 DESN.	6.7	2019-2020
LG-29	King City DS - New Station & Feeders	Construct a new 44-13.8kV DS. Build feeder ties with existing 13.8kV feeders from Eversley DS, and balance load between feeders / stations.	Provide a second 13.8 kV source of supply for King City to enable loop feeds and meet future load growth.	4.6	2019-2020
LG-30	New Old School DS	Construct a new 44-27.6kV DS. Construct 27.6kV feeders and tie to Snelgrove DS and Kleinburg TS M6.	Relieve capacity issues at Snelgrove DS, and provide a second 27.6kV source to improve loop feed supply.	7.0	2019-2020
LG-31	Town of Dundalk Voltage Conversion	Construct a new 44-8.32kV DS. Convert existing 4.16kV loads within the town of Dundalk to 8.32 kV, and remove existing 44-4.16kV transformer.	Provide increase station and feeder capacity to meet forecast load growth in Town of Dundalk.	9.5	2019-2021
LG-32	Greely DS F1 Feeder Development	Extend F1 feeder from Greely DS to offload existing feeders.	To meet forecast load growth in south Ottawa.	1.5	2020
LG-33	Kirkland Lake Voltage Conversion-Part 3	Convert Kirkland Lake DS #1 F1, F2, F3 feeders from 4.16 kV to 12.5 kV and re-supply from Goodfish DS and Woods DS. Remove Kirkland Lake DS #1.	Meet future load needs in the Town of Kirkland Lake and eliminate Kirkland Lake DS #1 which has obsolete switchgear and is located inside the Kirkland Lake TS yard.	2.8	2020
LG-34	Midhurst Wilson DS F2 Extend to Doran Rd	Overbuild 6.5km of existing 8.32 kV line with new 27.6 kV feeder from Wilson Road to Doran Road.	To meet future residential subdivision growth in the north-east Midhurst Area (Midhurst Secondary Plan – Neighbourhood 2).	2.2	2020
LG-35	Midhurst Wilson DS F1 Extend to Dobson Rd	Extend Midhurst Wilson DS 27.6 kV feeder for 3.5 km to Dobson Rd by converting existing Grenfel DS F2 feeder from 8.32 kV to 27.6 kV.	Address forecast overloading of Grenfel DS F2 feeder due to residential subdivision load growth.	2.2	2020
LG-36	Perth Area Upgrades	Reconstruct station egress's with higher capacity underground cable.	Provide back feed capability for single contingency station transformer outage.	2.0	2020

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-37	Macville DS - New 27.6kV Station	Extend Kleinburg TS M26 44 kV feeder for 2km and construct a new 44-27.6kV DS.	Provide Additional DS capacity to meet forecast load growth in the Town of Caledon.	3.7	2020-2021
LG-38	Wikwemikong DS & Line Work	Build a 15 kV 44 kV feeder extension by overbuilding existing a 12.5 kV line and construct a new 44-12.5 kV station. Upgrade an additional 3 km of existing 12.5 kV line to double-circuit.	To meet forecast load growth at Wikwemikong First Nation on Manitoulin Island.	6.5	2020-2021
LG-39	Dunchurch DS F2 - Extend to Magnetewan	Upgrade 10 km of existing single-phase line to three-phase and build 1 km new line to extend Dunchurch DS F2 feeder to Town of Magnetewan.	Provide load relief to Burks Falls DS F2 feeder which is loaded above planning guidelines and does not meet system protection criteria.	2.8	2021
LG-40	Fairbanks Lake Line Upgrade	Upgrade 2.6 km existing single-phase line to three-phase and build 8.7 km of new three-phase line.	To Address Substandard Feeder Protection on existing Whitefish DS F1.	2.5	2021
LG-41	Kleinburg TS M26 extension to Mayfield West	Extend Kleinburg TS M26 to Mayfield West (approximately 12 km).	Provide load relief to Pleasant TS M21 feeder based on forecast loading.	3.2	2021
LG-42	Lively DS F2 SW142 Upgrade Black Lake Road	Upgrade 5 km of single-phase line to three-phase.	Address single phase line loading above planning guidelines.	1.4	2021
LG-43	Mar DS – New Station	Construct a new 44-12.5 kV station and 2 km of new 12.5 kV feeders.	Provide load relief to Colpoys Bay DS which is loaded above the transformer Planned Load Limit (PLL).	3.0	2021
LG-44	Ancaster West DS Transformer Upgrade	Upgrade Ancaster West DS transformer from 5 MVA to 7.5 MVA.	Provide DS Capacity to meet forecast load growth.	2.0	2021-2022
LG-45	Brockville 44kV System Upgrades	Extend Brockville M7 and Morrisburg M24 feeders to off load B1R and M5 feeders.	Provide load relief to Brockville TS B1R & M5 feeders which are currently loaded above planning guidelines.	10.5	2021-2022

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-46	Manitoulin TS - Add Third 44 kV Feeder	Add new 44 kV breaker at Manitoulin TS, new feeder tie switches, and construct 1.5 km new 44 kV line to Little Current DS.	To maintain 44 kV feeder loading within protection limits during transformer or breaker outages.	4.6	2021-2022
LG-47	Point Au Baril DS F2 Extension	Extend the Point Au Baril DS F2 feeder for 8.5 km by double-circuit the existing F1 feeder north of Point Au Baril.	To provide load relief to the Point Au Baril DS F1 feeder which has substandard system protection and voltage.	3.6	2021-2022
LG-48	Aspdin DS F1 Feeder Upgrade	Upgrade 5 km of single-phase line to three-phase.	Address single phase line loading above planning guidelines.	1.3	2022

TAB 3

Anwaatin Inc. Interrogatory # 8

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Issue 29: Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?

Reference:

A-04-02 Page: 7

> "*In the past year, Hydro One has mapped out all transmission lines and distribution stations and feeders serving First Nations communities and collected relevant system reliability data in order to make sound and targeted investments to improve system reliability for First Nations communities. First Nation communities served by Hydro One are supplied from 55 transmission lines and 89 distribution lines. Historically, approximately 77% of power failures on these transmission lines were caused by deteriorated equipment (e.g., insulators, wood poles, conductor, etc.) or caused by adverse weather (freezing rain, ice, lightning, etc.) Approximately 50% of power failures on distribution lines occur from tree contacts which lead to equipment failures (e.g., poles, transformers, lines failures, etc.).*
>
> "*Hydro One will be implementing a three-pronged strategy that is intended to increase system reliability within First Nations communities. The strategy consists of: increasing capital investments and replacing equipment that affects reliability; leveraging technology to allow Hydro One to better detect, limit the scope, and remotely respond to certain types of outages; and reducing planned outages by bundling work.*"

Interrogatory:

a) Please provide maps of all the transmission lines, distribution stations and feeders serving First Nations communities referenced above and a description of each such asset, its age, useful life, and planned replacement date.

b) Please provide all system reliability data collected identifying what applies to distribution lines and highlight the relevant data, stations and feeders serving First Nations communities referenced above and the Anwaatin communities.
c) Please provide a chart comparing the reliability data in referred to in (b) with the data for Hydro One's R1, R2, and UR customers on a year-by-year basis for the last 10 years.

d) Please provide a chart delineating which power failures were on transmission lines, distribution lines/assets and the cause of the failure for each distribution asset or mixed distribution/transmission asset serving
(i) First Nations communities; and
(ii) the Anwaatin communities.

e) Please provide the same chart for Hydro One's R1, R2, and UR customers on a year-by-year basis for the last 10 years.

f) Please also provide system reliability averages and trends over the 2007-2017 and 2006-2016 10-year periods for each of the following: First Nations communities, the Anwaatin communities, Hydro One's R1 customers, Hydro One's R2 customers, and Hydro One's UR customers.

g) Please provide a chart comparing the percentage of power failures on distribution lines serving: (i) First Nations communities and (ii) the Anwaatin communities that were caused by or related to trees with the percentage of failures caused by or related to trees on distribution lines serving Hydro One's R1, R2, and UR customers on a year-by-year basis for the last 10 years.

Please also provide averages of these percentages over the 10-year period for each of the following: First Nations communities, Hydro One's R1 customers, Hydro One's R2 customers, and Hydro One's UR customers.

h) Please provide a detailed list of the causes of the power failures on distribution lines and assets serving: (i) First Nations communities and (ii) the Anwaatin communities that were not related to trees.

i) Please provide the percentage of the total power failures on distribution lines and assets serving: (i) First Nations communities, (ii) the Anwaatin communities, and (iii) the rest of Ontario that were attributable to the causes outlined in (h) above.

Response:

a) The maps that have been developed by Hydro One to show the supply to all First Nations reserve lands are shown in Attachments 1 and 2. Attachment 3 also provides a list of First Nations communities' assets, age, condition, and in-service dates (where available).

   The process Hydro Ones uses to identify assets in need of replacement is explained in section Exhibit B1-1-1, DSP Section 2.1 (5.3.1 B) Needs Assessment.

Note: For the analysis from 8b-8i, only 5-year data from 2012-2016 is available. Data prior to 2012 is not available because the data has not been extracted or validated at this time, and it is a timely process to do so. Given the strict timelines, we have reported with readily available 5-year data.

---

b) Figure B.1 illustrates the 5 year average SAIDI values for feeders serving First Nations communities. Anwaatin feeders are highlighted in yellow.

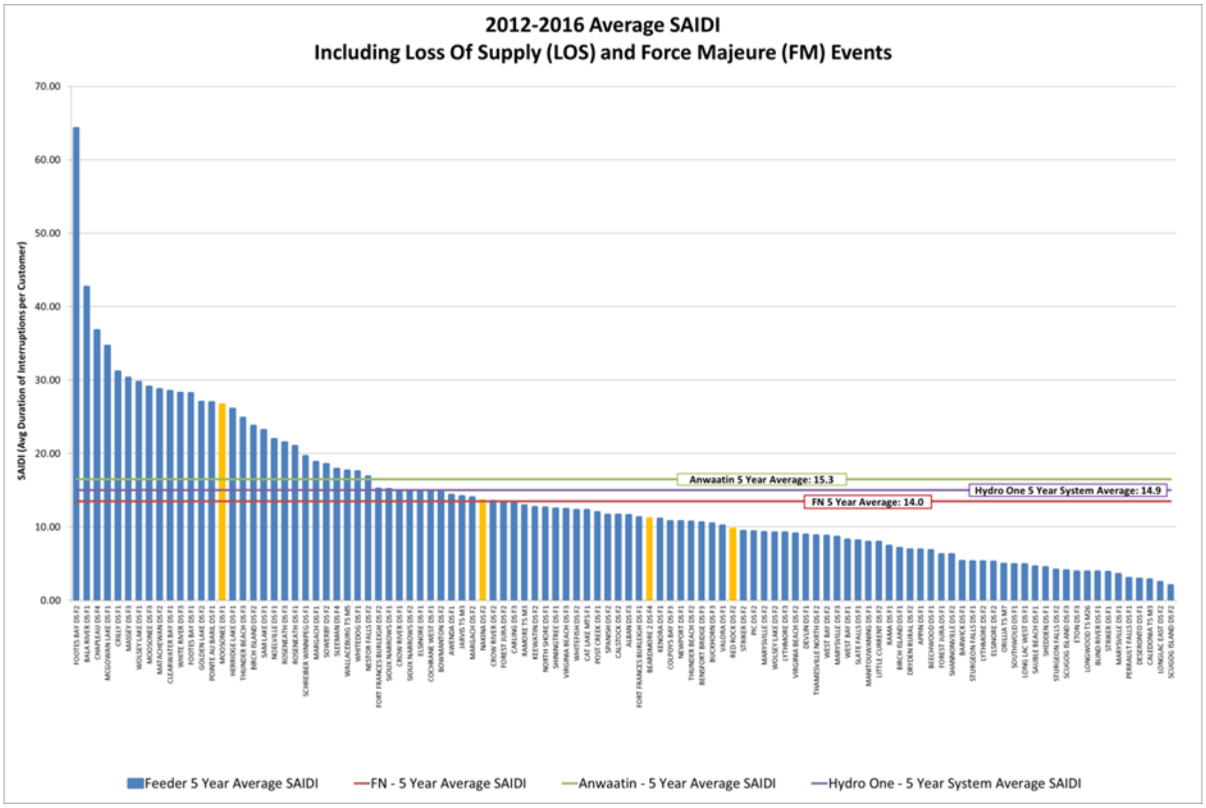


Figure B.1: 5 year average SAIDI for feeders supplying First Nations communities

Figure B.2 below, illustrates the 5 year average SAIFI values for feeders serving First Nations communities. Anwaatin feeders are highlighted in yellow.

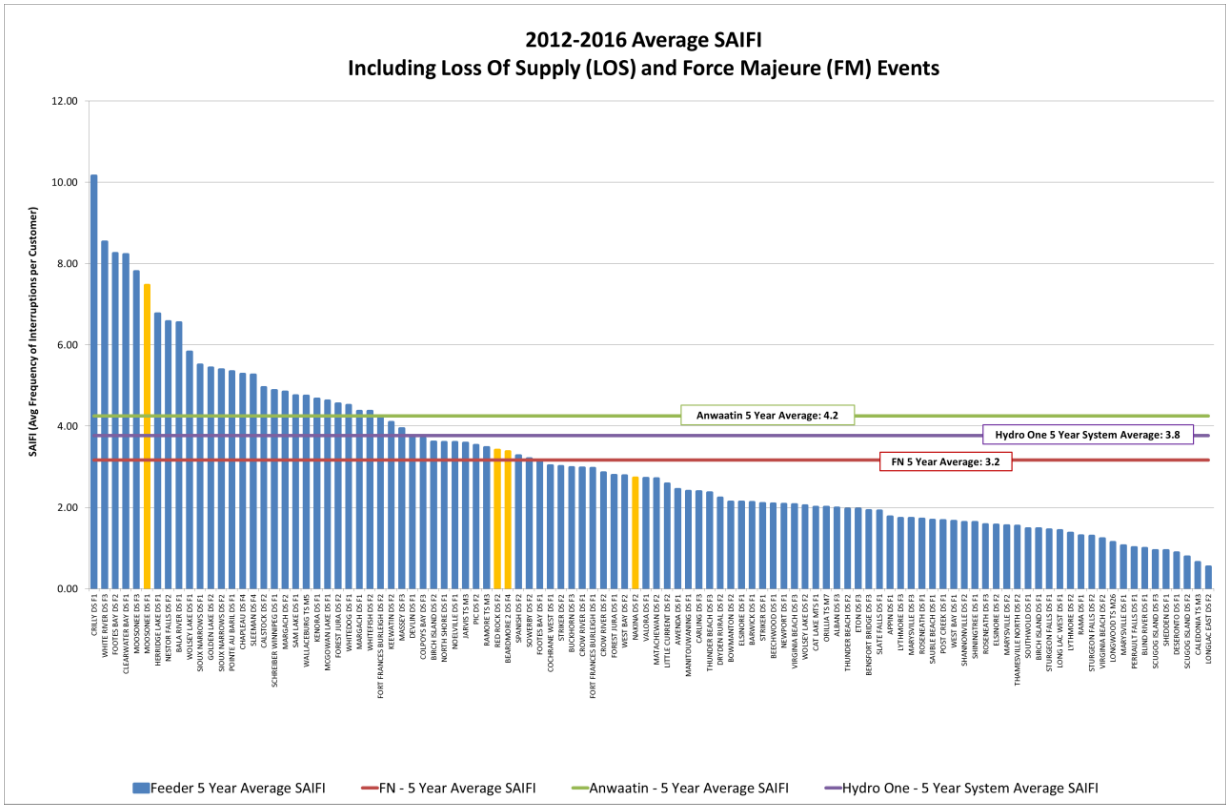


Figure B.2: 5 year average SAIFI for feeders supplying First Nations communities

c) Figures C.1 and C.2 compare the SAIDI and SAIFI values for feeders serving Anwaatin communities with Hydro One's Urban and Rural SAIDI and SAIFI on a year-by-year basis for the past five years.

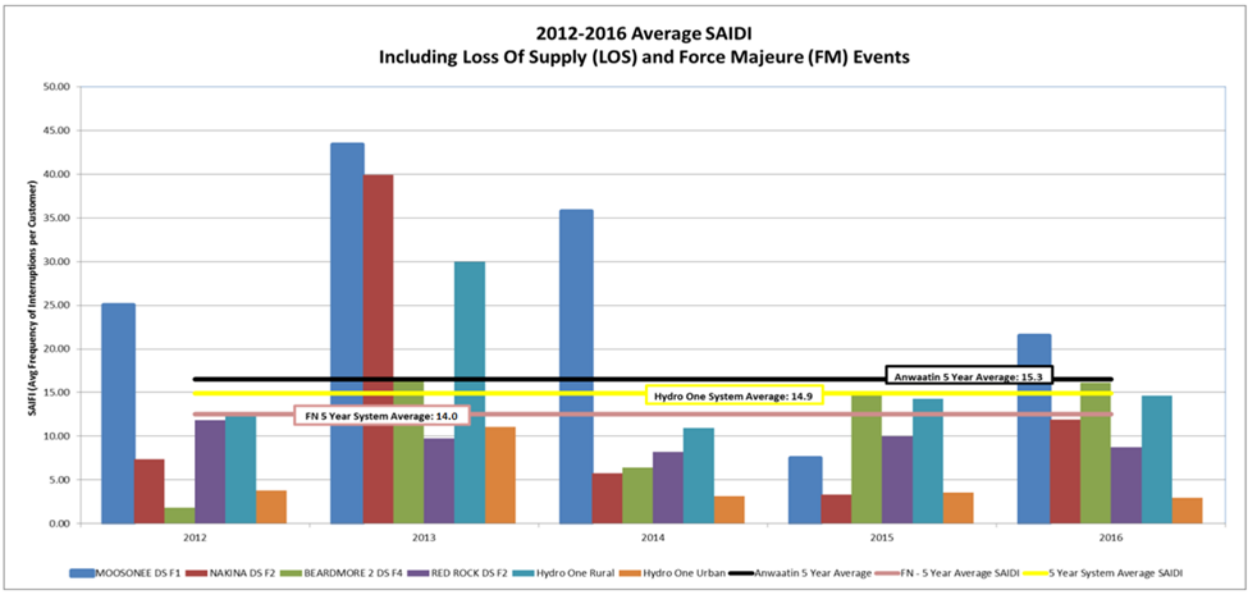


Figure C.1: Comparison of SAIDI from 2012-2016

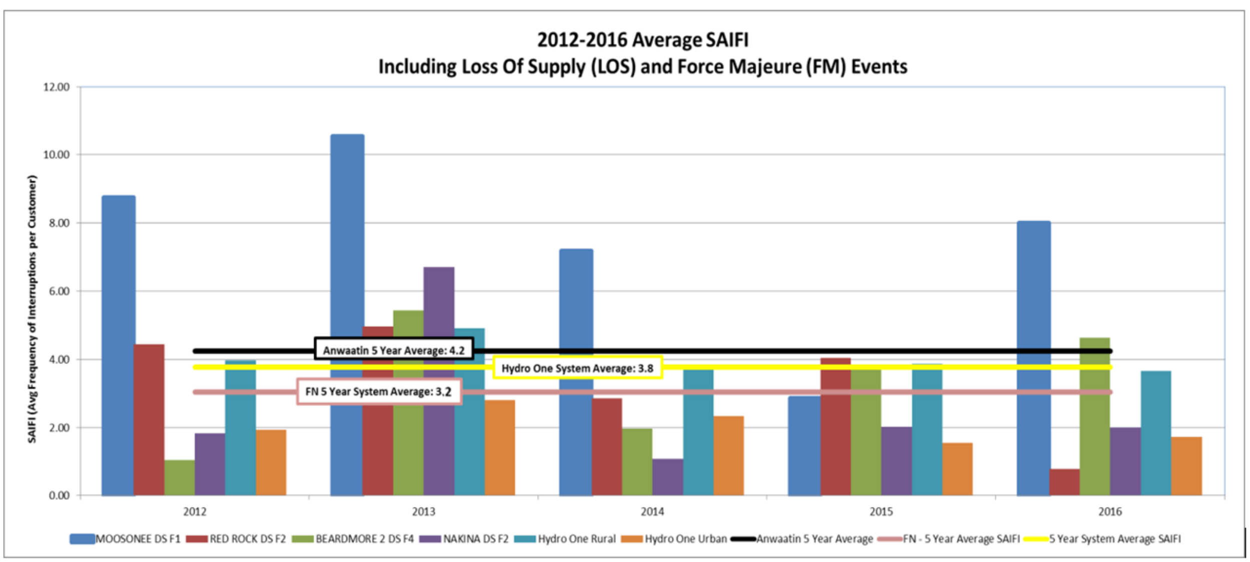


Figure C.2: Comparison of SAIFI from 2012-2016

Note: *The data is categorized as Urban (UR) and Rural (R1 and R2). Data from 2012-2016 is available.*

Witness: JESUS Bruno

d) When customers connected to Hydro One's distribution line experience an interruption, it is due to one of these 8 causes: Adverse Environment, Defective Equipment, Foreign Interference, Human Element, Loss of Supply, Scheduled, Tree Contacts, and Unknown/Other. Loss of Supply refers to customers being interrupted due to a loss of supply on the distribution side as a result of the transmission side.

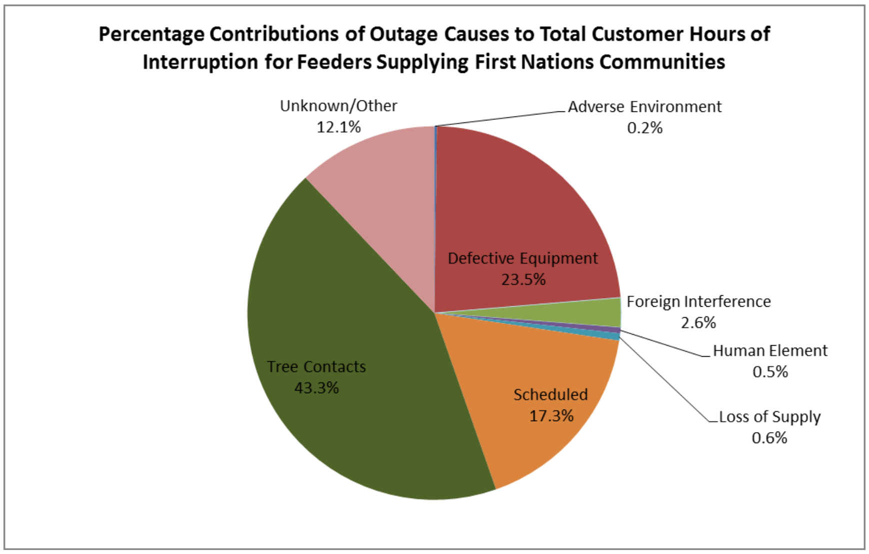


Figure D.1: Percentage Contributions of Outage Causes to Total Customer Hours of Interruption for Feeders Supplying First Nations Communities – based on data from 2012-2016

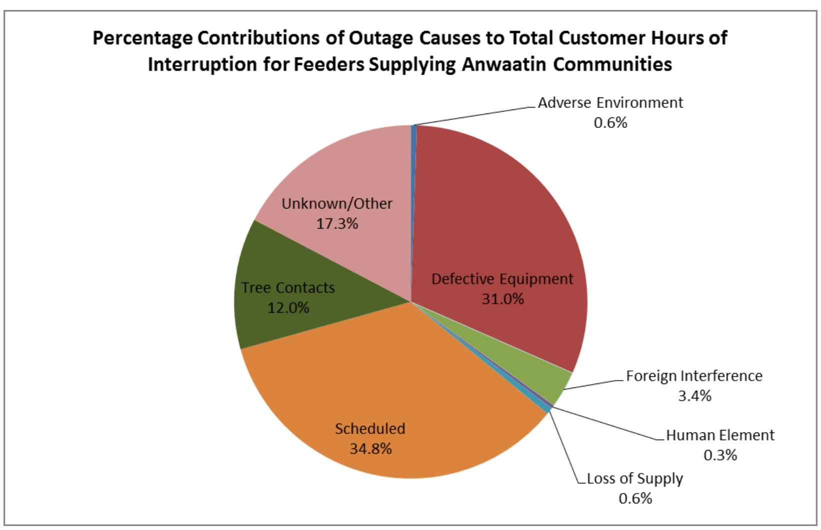


Figure D.2: Percentage Contributions of Outage Causes to Total Customer Hours of Interruption for Feeders Supplying Anwaatin Communities – based on data from 2012-2016 e)

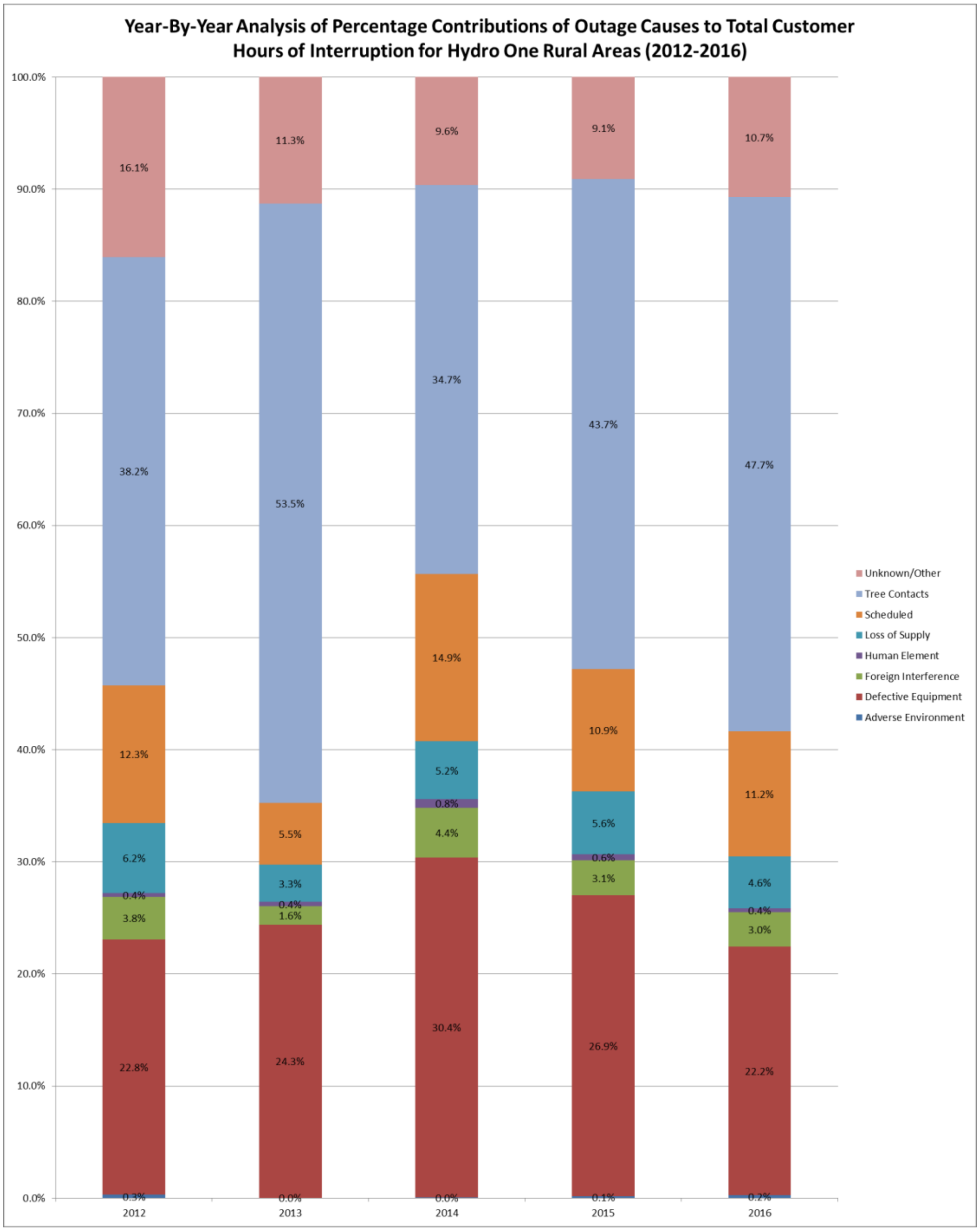


Figure E.1: Year-By-Year Analysis of Percentage Contributions of Outage Causes to Total Customer Hours of Interruption for Hydro One Rural Areas (R1 and R2 customers) – based on data from 2012-2016

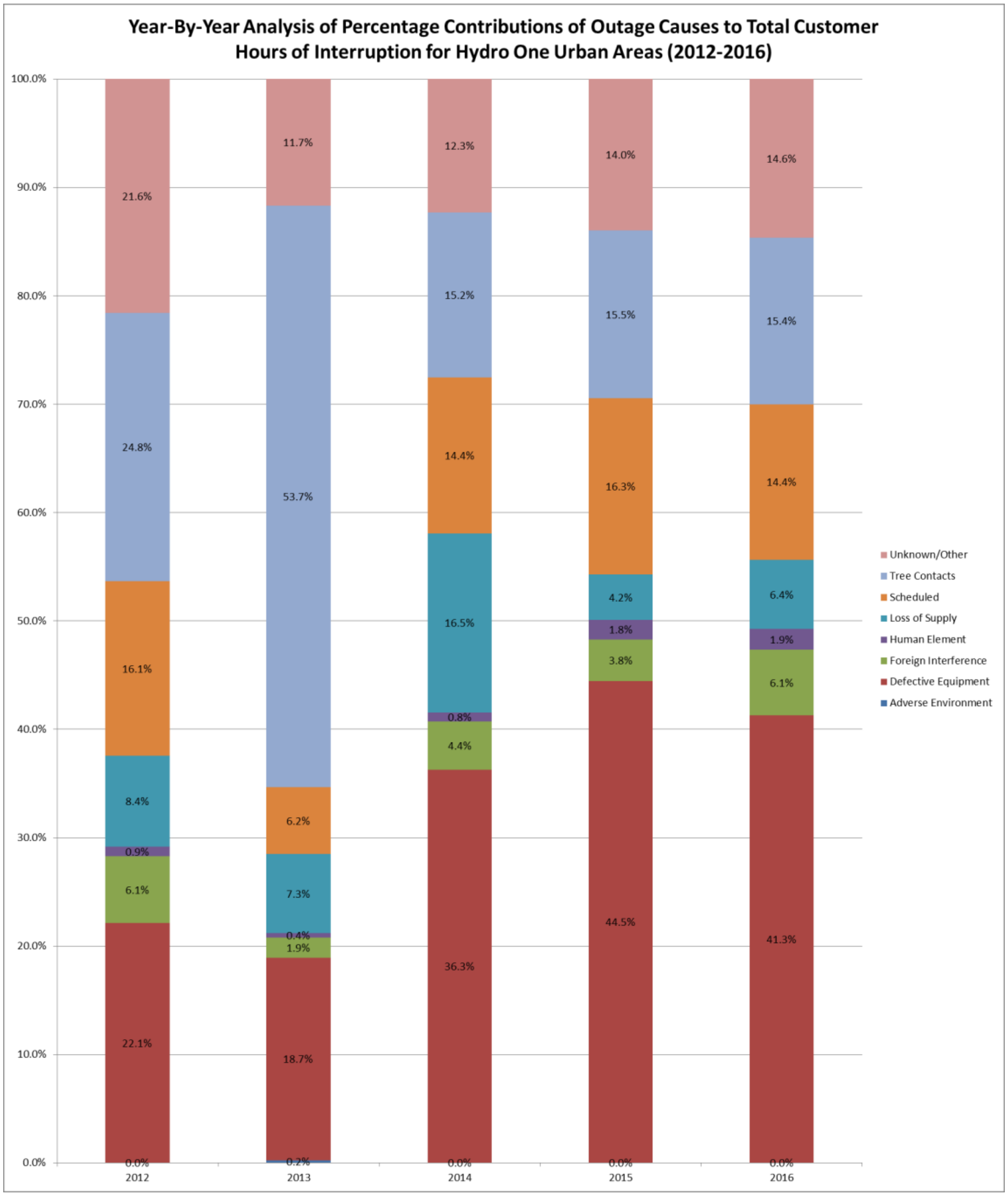


Figure E.2: Year-By-Year Analysis of Percentage Contributions of Outage Causes to Total Customer Hours of Interruption for Hydro One Urban Areas (UR Customers) – based on data from 2012-2016

Note: *The data is categorized as Urban (UR) and Rural (R1 and R2). Data from 2012-2016 is available.*

f) For system reliability averages and trends for feeders supplying First Nations communities and Anwaatin communities, please refer to part b) of this question.

For system reliability averages and trends for Hydro One's Urban and Rural areas, as well as averages and trends for the performance of First Nations communities and Anwaatin communities, please refer to part c of this question.

g)

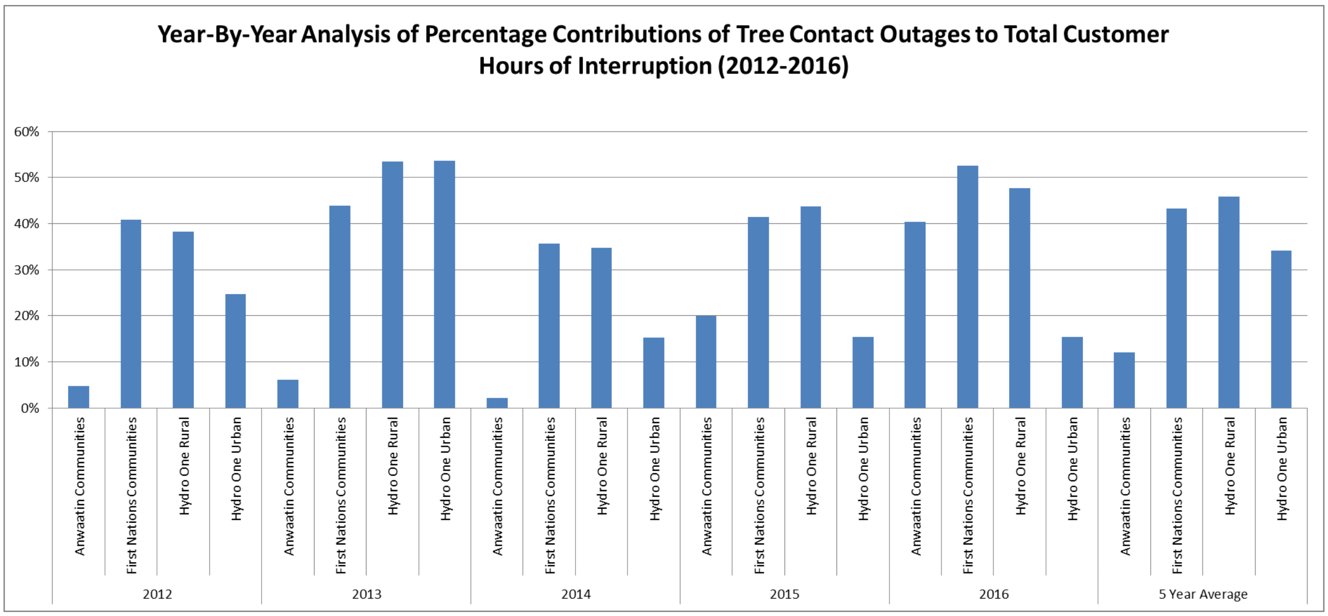


Figure G.1: Percentage Contributions of Tree Contact Outages to Total Customer Hours of Interruption for Feeders Supplying First Nations Communities – based on data from 2012-2016

Note: *The data is categorized as Urban (UR) and Rural (R1 and R2). Data from 2012-2016 is available.*

h) The causes of power failures, excluding Tree Contacts, on the distribution lines and assess are classified as follows:

a. Adverse Environment
b. Defective Equipment
c. Foreign Interference
d. Human Element
e. Loss of Supply
f. Scheduled
g. Unknown/Other

i) Illustrated below are the percentage contributions of each of the causes to the overall customer hours of interruption for First Nations communities (Figure I.1), Anwaatin Communities (Figure I.2), and all of Ontario (Figure I.3).

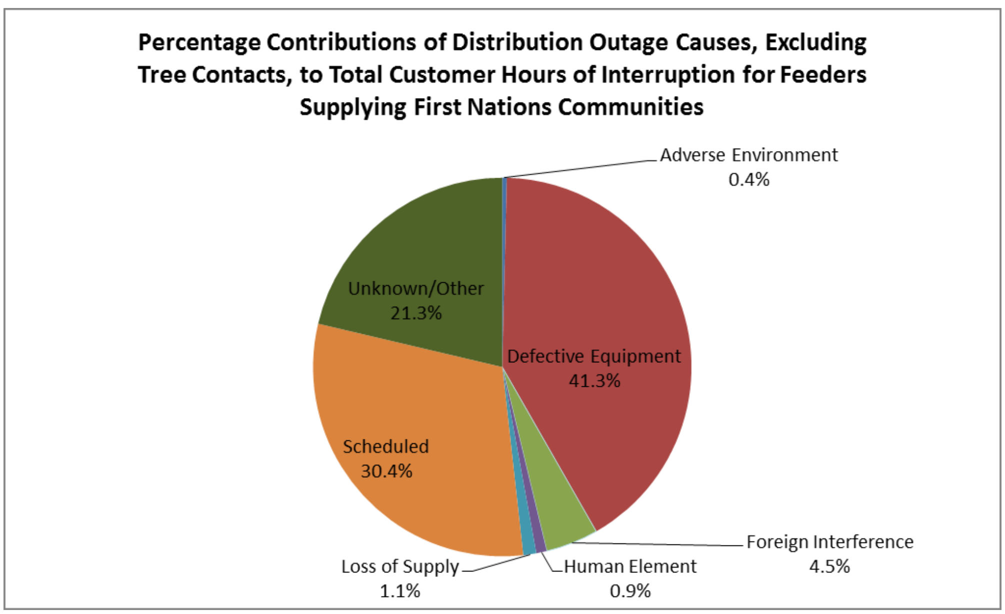


Figure I.1: Percentage Contributions of Distribution Outage Causes (Excluding Tree Contacts) to Total Customer Hours of Interruption for Feeders Supplying First Nations Communities – based on data from 2012-2016

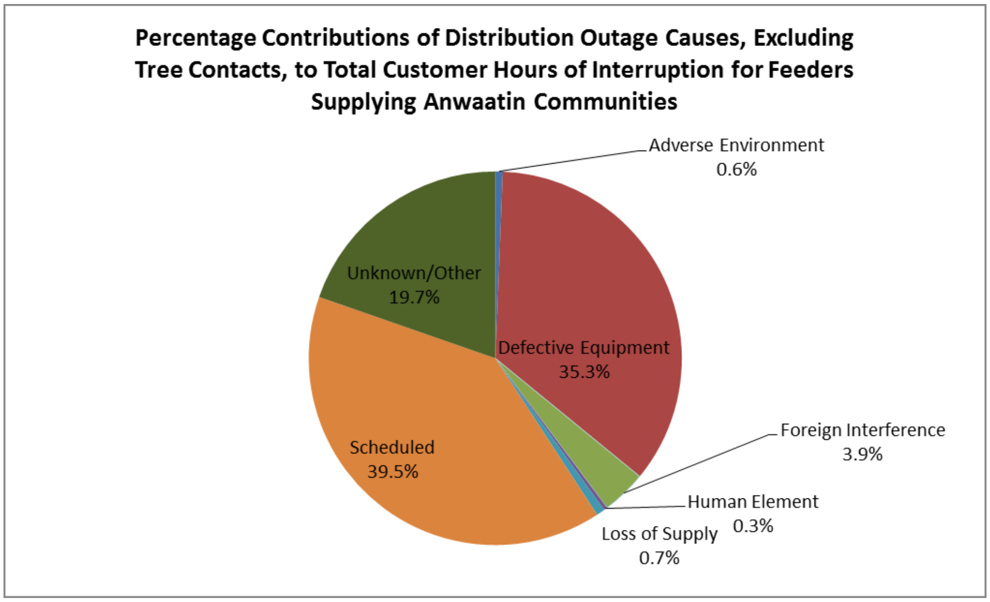


Figure 1.2: Percentage Contributions of Distribution Outage Causes (Excluding Tree Contacts) to Total Customer Hours of Interruption for Feeders Supplying Anwaatin – based on data from 2012-2016

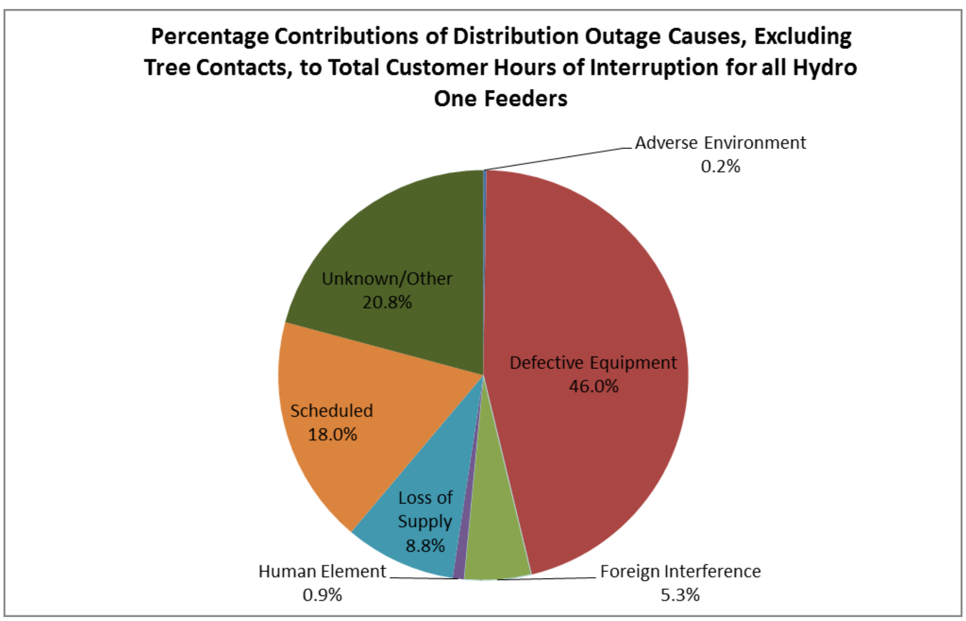


Figure 1.3: Percentage Contributions of Distribution Outage Causes (Excluding Tree Contacts) to Total Customer Hours of Interruption for all Hydro One Feeders – based on data from 2012-2016

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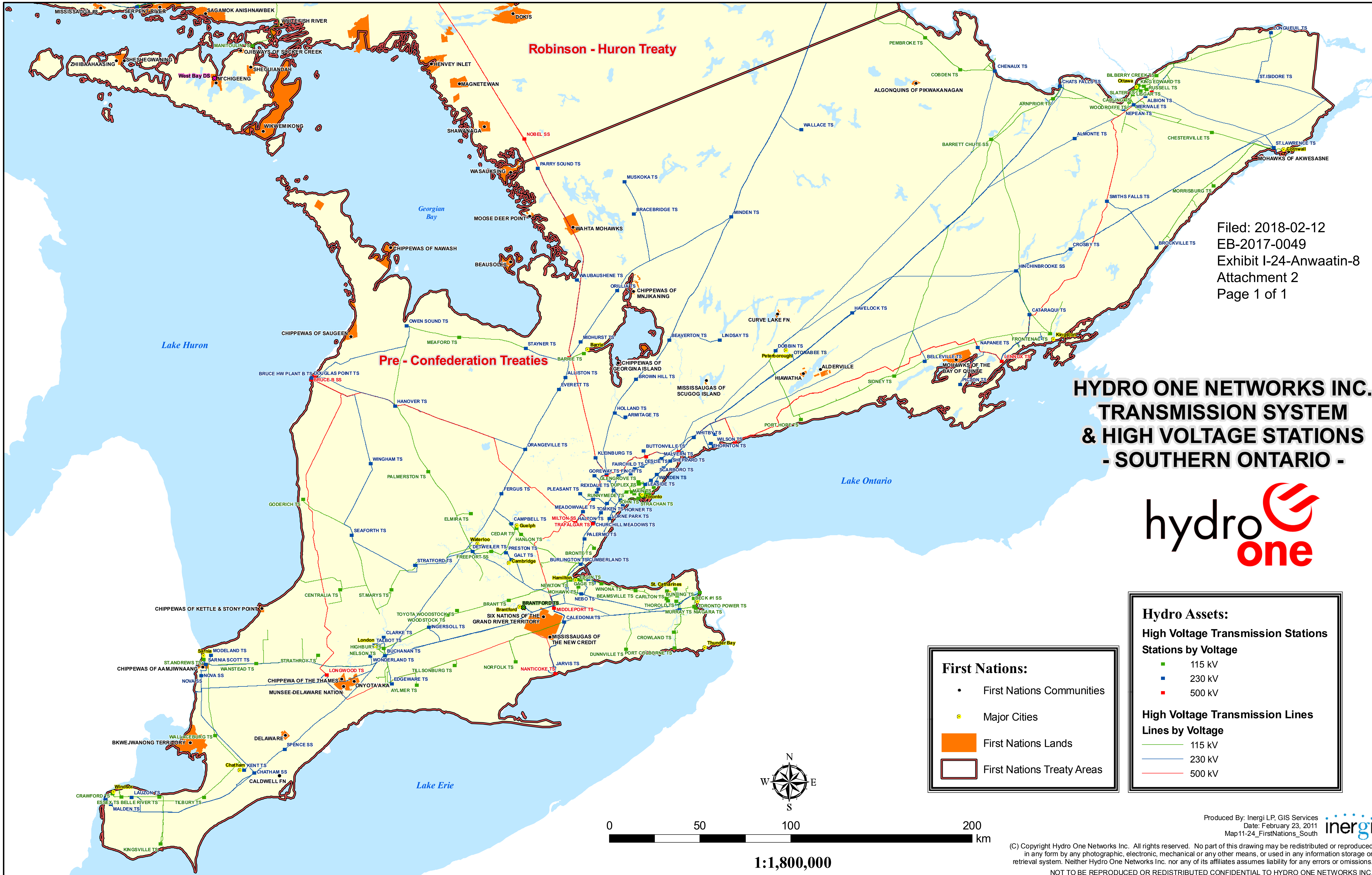
EB-2017-0049
Exhibit I-24-Anwaatin-8
Attachment 1
Page 1 of 1
HYDRO ONE NETWORKS INC.
TRANSMISSION SYSTEM
& HIGH VOLTAGE STATIONS
- NORTHERN ONTARIO -
Treaty 5
Treaty 9
Treaty 3
Robinson - Superior Treaty
Robinson - Huron Treaty
James Bay
Lake Superior
Lake Huron
Lake Nipigon
Georgian Bay
Hydro Assets:
High Voltage Transmission Stations
Stations by Voltage
115 kV
230 kV
500 kV
High Voltage Transmission Lines
Lines by Voltage
115 kV
230 kV
500 kV
First Nations:
First Nations Communities
Remote Communities
Major Cities
First Nations Lands
First Nations Treaty Areas
N
S
E
W
0
100
200
400
km
1:4,000,000
Produced By: Inergi LP, GIS Services
Date: February 23, 2011
Map11-24_FirstNations_North
KENORA
THUNDER BAY
FORT FRANCES
SAULT STE.MARIE
SUDBURY
TIMMINS
NORTH BAY



Filed: 2018-02-12
EB-2017-0049
Exhibit I-24-Anwaatin-8
Attachment 2
Page 1 of 1
HYDRO ONE NETWORKS INC.
TRANSMISSION SYSTEM
& HIGH VOLTAGE STATIONS
- SOUTHERN ONTARIO -
hydro one
Robinson - Huron Treaty
Pre - Confederation Treaties
Georgian Bay
Lake Huron
Lake Ontario
Lake Erie
First Nations:
First Nations Communities
Major Cities
First Nations Lands
First Nations Treaty Areas
Hydro Assets:
High Voltage Transmission Stations
Stations by Voltage
115 kV
230 kV
500 kV
High Voltage Transmission Lines
Lines by Voltage
115 kV
230 kV
500 kV
N
W
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50
100
200
km
1:1,800,000
Produced By: Inergi LP, GIS Services
Date: February 23, 2011
Map11-24_FirstNations_South
inergi
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Community	Supply Station	Feeder	Average Pole Age	Pole Count	GOOD	FAIR	POOR	Project	I/S Date
Alderville First Nation	Bowmanton DS	F2	41	665	563	22	80		
Alderville First Nation	Roseneath DS	F1	39	482	422	33	27		
Alderville First Nation	Roseneath DS	F3	42	1025	929	69	27		
Big Grassy First Nation	Sleeman DS	F4	42	2389	2089	270	30		
Chippewas of Nawash Unceded First Nation	Colpoys Bay DS	F3	45	2836	2053	738	45		
Constance Lake First Nation	Calstock DS	F2	35	335	64	269	2		
Couchiching First Nation	Burleigh DS	F1	30	726	592	113	21		
Wahta Mohawks First Nation	Bala River DS	F1	41	1902	263	832	807	WPF	2018/2019
Wahta Mohawks First Nation	Footes Bay DS	F1	39	1664	1524	122	18		
Wahta Mohawks First Nation	Footes Bay DS	F2	44	1281	1226	38	17		
Pic River First Nation (Biigtigong Nishnaabeg First Nation)	Pic DS	F2	32	1512	1335	73	104		
Lac Seul First Nation	Sam Lake DS	F1	26	711	568	128	15		
Magnetawan First Nation	Pointe Au Baril DS	F1	44	2361	1831	357	173		
Rainy River First Nation	Barwick DS	F1	35	1564	1367	174	23		
Moose Deer Point First Nation	Footes Bay DS	F2	44	1281	1226	38	17		
Anishinaabeg of Naongashiing	Sleeman DS	F4	42	2389	2089	270	30		
Eagle Lake	Eton DS	F3	27	1869	1709	125	35		
Asubspeeschoseewagong Netum Anishinabek (Grassy Narrows)	Margach DS	F2	27	2524	2130	319	75		
Lac La Croix	Crilly DS	F1	30	2103	2003	69	31		
Nipissing First Nation	Sturgeon Falls DS	F1	35	833	720	82	31		
Nipissing First Nation	Sturgeon Falls DS	F2	35	800	693	51	56		
Animakee Wa Zhing #37	Sioux Narrows DS	F2	37	833	766	54	13		
Ojibways of Onigaming First Nation	Nestor Falls DS	F2	36	923	722	167	34		
Mishkeegogamang	Crow River DS	F1	21	964	927	35	2		
Mishkeegogamang	Crow River DS	F2	35	454	411	37	6		
Wasauksing First Nation	McGowan Lake DS	F1	44	2314	1913	274	127		
Pays Plat	Schreiber Winnipeg DS	F1	31	1367	1273	68	26		
Naicatchewenin	Devlin DS	F1	41	1316	1174	109	33		
Nigigoonsiminikaaning First Nation	Burleigh DS	F2	35	1210	997	157	56		
Biinjitiwaabik Zaaging Anishinaabek (BZA) aka Rocky Bay First Nation	Beardmore DS #2	F4	30	860	734	96	30		
Mississaugas of Scugog Island First Nation	Scugog Island DS	F2	36	348	318	9	21		
Mississaugas of Scugog Island First Nation	Scugog Island DS	F3	40	399	390	9	0		
Seine River First Nation	Crilly DS	F1	30	2103	2003	69	31		
Iskatewizaagegan #39 Independent First Nation	Clearwater Bay DS	F1	32	1265	1038	146	81		
Shoal Lake No. 40	Clearwater Bay DS	F1	32	1265	1038	146	81		
Slate Falls First Nation	Slate Falls DS	F1	24	198	195	3	0		
Sagamok Anishnawbek	Massey DS	F3	40	2668	2050	590	28		
Mohawks of the Bay of Quinte	Deseronto DS	F1	32	187	113	69	5		
Mohawks of the Bay of Quinte	Shannonville DS	F2	35	821	748	72	1		
Mohawks of the Bay of Quinte	Marysville DS	F1	32	496	414	67	15		
Mohawks of the Bay of Quinte	Marysville DS	F2	33	2055	1394	325	336		
Mohawks of the Bay of Quinte	Marysville DS	F3	27	1009	851	128	30		
Mohawks of the Bay of Quinte	Beechwood DS	F1	32	404	327	46	31		
Wabaseemoong Independent Nations	Whitedog DS	F1	24	369	303	47	19		

Wabigoon Lake Ojibway Nation	Dryden Rural DS	F2	38	2268	1478	665	125		
Obashkaandagaang	Keewatin DS	F2	29	1326	1137	144	45		
Naotkamegwanning	Sioux Narrows DS	F1	35	862	770	87	5		
Naotkamegwanning	Sioux Narrows DS	F2	37	833	766	54	13		
Aroland	Nakina DS	F2	30	324	305	16	3		
Brunswick House, Chapleau Cree FN, Chapleau Ojibway FN	Chapleau DS	F4	43	1202	1027	122	53		
Chippewas of The Thames First Nation	Longwood TS	M26	40	946	904	38	4		
Chippewas of The Thames First Nation	Appin DS	F1	47	1796	1752	39	5		
Beausoloeil First Nation	Thunder Beach DS	F2	39	845	594	235	16	WPF	2018/2019
Beausoloeil First Nation	Thunder Beach DS	F3	38	418	95	305	18	WPF	2018/2019
Beausoloeil First Nation	Awenda DS	F1	30	1306	1079	195	32	WPF	2018/2019
Zhiibaahaasing First Nation	Wolsey Lake DS	F1	36	2360	2180	98	82		
Curve Lake First Nation	Buckhorn DS	F3	37	1577	1483	73	21	WPF	2018/2019
Ochiichagwe'babigo'ining First Nation	Kenora DS	F1	31	1811	1473	256	82		
Dokis	Noelville DS	F1	44	1333	1093	218	22	WPF	2018/2019
Chippewas of Georgina Island First Nation	Virginia Beach DS	F2	47	545	517	16	12		
Chippewas of Georgina Island First Nation	Virginia Beach DS	F3	35	727	685	31	11		
Algonquins of Pikwakanagan	Golden Lake DS	F2	35	2193	496	1622	75	WPF	2018/2019
Red Rock (aka Lake Helen First Nation)	Red Rock DS	F2	32	1328	1126	183	19		
Henvey Inlet	Alban DS	F3	41	1409	1381	25	3	WPF	2018/2019
Hiawatha First Nation	Bensfort Bridge DS	F3	40	1179	854	299	26		
Temagami First Nation	Herridge Lake DS	F1	42	543	425	55	63		
Chippewas of Kettle and Stony Point First Nation	Forest Jura DS	F1	34	1540	1193	290	57		
Chippewas of Kettle and Stony Point First Nation	Forest Jura DS	F2	38	1166	777	36	353		
Long Lake No. 58 First Nation	Longlac West DS	F1	34	369	331	28	10		
Ginoogaming First Nation	Longlac East DS	F2	37	258	227	17	14		
Matachewan	Matachewan DS	F2	18	230	182	3	45		
Mattagami	Shiningtree DS	F1	30	2229	1030	1194	5		
Mississauga	North Shore DS	F1	36	1423	1275	105	43		
Mississauga	Blind River DS	F1	39	82	77	4	1		
Mississauga	Striker DS	F1	36	770	708	45	17		
Mississauga	Striker DS	F2	35	1949	1839	81	29		
Pic Mobert	White River DS	F3	25	587	455	11	121		
Moose Cree First Nation	Moosonee DS	F1	30	665	265	351	49		
Moose Cree First Nation	Moosonee DS	F3	33	515	388	67	60		
Delaware Nation	Thamesville North DS	F2	47	1541	1489	46	6		
Munsee-Delaware Nation	Appin DS	F1	47	1796	1752	39	5		
Munsee-Delaware Nation	Longwood TS	M26	40	946	904	38	4		
Mississaugas of The New Credit First Nation	Lythmore DS	F2	33	1095	60	1017	18		
Mississaugas of The New Credit First Nation	Lythmore DS	F3	35	1119	597	496	26		
Mississaugas of The New Credit First Nation	Jarvis TS	M3	31	3399	3276	106	17		
Taykwa Tagmou Nation	Cochrane West DS	F1	47	3602	1185	2335	82		
Northwest Angle No. 33 / Whitefish Bay 33A	Sioux Narrows DS	F2	37	833	766	54	13		
Oneida Nation of the Thames	Southwold DS	F1	37	921	901	12	8		
Oneida Nation of the Thames	Shedden DS	F1	45	2538	2469	56	13		
Stanjikoming/Mitaanjigamiing First Nation	Burleigh DS	F1	30	726	592	113	21		

Chippewas of Rama First Nation	Rama DS	F1	42	650	631	11	8		
Chippewas of Rama First Nation	Orillia TS	M7	26	859	578	240	41		
Anishinabe of Wauzhushk Onigum (Rat Portage)	Margach DS	F1	35	916	809	89	18		
Saugeen First Nation	Elsinore DS	F1	44	1031	639	328	64	WPF	2018/2019
Saugeen First Nation	Elsinore DS	F2	43	748	674	25	49	WPF	2018/2019
Saugeen First Nation	Sauble Beach DS	F1	44	496	453	40	3	WPF	2018/2019
Ojibway Nation of the Saugeen	Valora DS	F1	37	1476	1376	95	5		
Serpent River	Spanish DS	F2	38	1195	1028	147	20		
Shawanaga First Nation	Carling DS	F3	34	770	686	75	9		
Sheguiandah	Little Current DS	F2	39	2314	2087	178	49		
Sheshegwaning	Wolsey Lake DS	F1	36	2360	2180	98	82		
Sheshegwaning	Manitouwaning DS	F1	35	1738	1561	164	13	WPF	2018/2019
Sheshegwaning	West Bay DS	F2	35	1023	612	279	132		
Six Nations of the Grand River	Lythmore DS	F2	33	1095	60	1017	18		
Six Nations of the Grand River	Lythmore DS	F3	35	1119	597	496	26		
Six Nations of the Grand River	Jarvis TS	M3	31	3399	3276	106	17		
Six Nations of the Grand River	Caledonia TS	M3	34	456	36	411	9		
Six Nations of the Grand River	Newport DS	F1	35	1535	677	804	54		
Aundeck-Omni-Kaning	Little Current DS	F2	39	2314	2087	178	49	WPF	2018/2019
Thessalon	Sowerby DS	F2	46	1113	911	170	32		
Wabauskang First Nation	Perrault Falls DS	F1	34	883	685	172	26		
Wahgoshig	Ramore TS	M3	37	1342	1249	62	31		
Wahnapitae	Post Creek DS	F1	19	113	112	1	0		
Walpole Island	Wallaceburg TS	M5	38	2409	2345	61	3		
M'Chigeeng First Nation	West Bay DS	F1	34	695	477	210	8		
M'Chigeeng First Nation	West Bay DS	F2	35	1023	612	279	132		
Whitefish Lake (Atikameksheng Anishnawbek)	Whitefish DS	F2	48	929	841	77	11		
Whitefish River	Birch Island DS	F1	38	1008	732	205	71	WPF	2018/2019
Whitefish River	Birch Island DS	F2	33	834	703	103	28	WPF	2018/2019
Wikwemikong	Manitouwaning DS	F1	35	1738	1561	164	13		
Wikwemikong	Wolsey Lake DS	F2	34	697	611	60	26		
Caldwell First Nation	Kingsville TS	M1	44	2224	2126	93	5		
Animbigoo Zaagiigan Anishinaabek (AZA)	Jellicoe DS #3	F1	26	440	428	11	1		
MoCreebec Eeyoud aka Moose Cree FN	Moosonee DS	F1	30	665	265	351	49		

WPF = Worst Performing Feeder Investment

Refer to ISD: SR-06 for a list of Station Refurbishment Investments

TAB 4

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Frank D'Andrea
Vice President
Regulatory Affairs

BY COURIER

June 15, 2018

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

Dear Ms. Walli,

EB-2017-0049 - Interrogatory Response Update in Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application (the "Application")

Please find enclosed the updated interrogatory I-06-Anwaatin-001 for Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application. This update takes into account a new pilot project initiative that Hydro One is evaluating in the area that serves Anwaaatin communities.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Enc.

Anwaatin Inc. Interrogatory # 1

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

A-04
A-04-02

Preamble:

Hydro One's distribution business serves the majority of the First Nations and Métis communities in Ontario.

In the Application, Hydro One states that it will be implementing a three-pronged strategy that is intended to increase system reliability within First Nations communities (increasing capital investments and replacing equipment that affects reliability; leveraging technology to allow Hydro One to better detect, limit the scope, and remotely respond to certain types of outages; and reducing planned outages by bundling work).

Hydro One indicates that, through its First Nations and Métis Strategy (Exhibit A, Tab 4, Schedule 2), communities would like to see an increase in procurement, investment/ownership opportunities, and other business partnership opportunities for Aboriginal businesses. Hydro One further indicates that First Nations communities have raised concerns about the high frequency and duration of power outages, particularly in Northern Ontario. Some communities have also indicated that the electricity supply is not sufficiently reliable to serve businesses on reserve and are concerned about degrading Hydro One asset conditions on reserve.

Hydro One also notes that First Nations communities and customers feel they are disproportionately impacted by high electricity costs. Many have raised concerns that their delivery charge is higher than their electricity consumption. In addition, First Nations customers are most sensitive to cost and place the greatest importance on cost over improvements in the service they receive.

Hydro One indicates that it hopes to address many of the Indigenous concerns with reliability and distributed energy resources, including Indigenous investment and ownership, and is developing a consolidated framework to guide First Nations and Métis relations and engagement across all lines of business.

Interrogatory:

a) Please describe how Hydro One consulted First Nations on any and all investment/ownership opportunities and other business partnership opportunities related to DERs in grid-connected communities, and what resulted from these consultation efforts.

b) Please describe in detail and provide all reports, notes, memos and documents related to:

   i. all processes Hydro One undertook to consult with Indigenous communities on this distribution rate application; and
   ii. the outcome of those consultations.

c) Please list each and all distributed energy resources that:

   i. Hydro One considered for Indigenous communities;
   ii. Hydro One consulted with First Nations on;
   iii. Hydro One implemented or intends to implement for Indigenous communities;
   iv. the Hydro One actions that result from them; and
   v. the quantified improvements in reliability and service that result from them.

d) Since First Nations in Ontario have now acquired or will soon acquire more than 14 million shares of Hydro One (representing 2.4% of the outstanding common shares of Hydro One), please describe how Hydro One will address the significant concerns of Indigenous shareholders relating to the high frequency and duration of power outages in Indigenous communities and the disparate reliability afforded to this class of shareholder.

Response:

a) Hydro One engages First Nations on investment/ownership opportunities on a project by project basis such as the Bruce to Milton Transmission Project and the Niagara Reinforcement Project. At this time, Hydro One has not yet engaged First Nations on any investment/ownership opportunities and other business partnership opportunities related to distributed energy resources (DERs) in grid-connected communities. Hydro One has recently begun exploring opportunities to partner with interested First Nation communities and to leverage federal and provincial government funding to support green energy and greenhouse gas reducing energy projects.

b)

i) Hydro One regularly engages with First Nations and Métis communities about various issues of concern.

As part of its review of customer needs and preferences, Hydro One conducted a telephone survey in August 2016 of a random and representative sample of 300 First Nations customers. A key finding was that First Nations customers are most sensitive to cost and place the greatest importance on cost over improvements in the service they receive. A copy of the telephone survey results with First Nations customers can be found EB-2017-0049, Exhibit B1-1-1, Section 1.3, Attachment 1, pages 1562 to 1570.

In addition, Hydro One also held engagement sessions with (a) the 88 First Nation communities it serves on February 9 and 10, 2017, the session reports for which are provided as Attachment 4 to section 1.3 of the DSP (Exhibit B1, Tab 1, Schedule 1) and (b) the 29 Métis Councils represented by the Métis Nation of Ontario on May 13, 2017. The purpose of the sessions was to engage on Application as well as to share information on various programs and initiatives benefiting Indigenous communities and to hear about issues and concerns expressed by participants as they related to Hydro One. Please find enclosed reports, presentations, and notes related to these engagement sessions as Attachments 1 to 9.

Hydro One will be hosting a second First Nations Engagement Session on February 21, 2018 which will be open to representatives of the 88 First Nations communities it serves. A similar engagement session will be offered to the Métis Nation of Ontario in 2018.

ii) For the most part, Hydro One had existing initiatives in place to address the concerns raised in these engagement sessions. Hydro One made 35 specific commitments at the

February 9 and 10, 2017 First Nation engagement session and 95% of these commitments were addressed throughout the year. Hydro One made 10 specific commitments at the May 13, 2017 engagement session with the Métis Nation of Ontario. Attachment 10 lists the 10 questions asked by the Métis Nation of Ontario and includes Hydro One responses.

The outcomes of these engagement sessions was the development of additional strategies and plans responsive to the key issues and concerns expressed by participants as they related to the transmission and distribution system.

To improve affordability, Hydro One implemented an outreach plan to ensure all eligible First Nation customers benefit from the First Nations Delivery Credit announced as part of the Ontario Fair Hydro Plan and which came into effect on July 1, 2017. Hydro One also adjusted a plan to implement the First Nations Conservation Program (FNCP) in new First Nation communities in 2018. The FNCP is a follow-up program to the Aboriginal Conservation Program which was implemented by the Independent Electricity System Operator (IESO) and ended in 2015 after providing services to 39 communities. The FNCP is designed to serve the communities not served by the IESO's earlier program**.**

In addition, Hydro One also implemented the Get Local Initiative to help customers by providing information about conservation programs and resources that may assist low-income customers and ensuring that qualifying customers are aware of and accessing the Province of Ontario's Ontario Electricity Support Program. Finally, in 2018 Hydro One started to roll-out the Affordability Fund to improve First Nations' home energy efficiency by providing free energy-saving upgrades, which can lower home energy use and, correspondingly, a customer's electricity bill over the long term.

In order to improve reliability and in response to complaints raised at the engagement sessions, Hydro One has revised its vegetation management policy whereby it will increase the frequency of forestry maintenance work on reserve. In addition, on measures to improve reliability, please see parts c) i), ii), and iii) of Exhibit I-6-Anwaatin-2.

On liability and access, Hydro One responded to feed-back committing to notify or seek permission as applicable from First Nation communities when conducting reconnection work on reserve in the context of its distribution business.

c) In its February 12, 2018 response to Exhibit I-6-Anwaatin-001 c), Hydro One stated that it had not yet considered distributed energy resources related to Indigenous communities. Hydro One has recently begun exploring opportunities to partner with interested First Nation communities and to leverage federal and provincial government funding to support green energy and greenhouse gas reducing energy projects.

By way of update, in April 2018, Hydro One commenced preliminary discussions with Anwaatin regarding renewable sourced generation interconnection capacity and energy storage capacity at distribution station locations in proximity to Anwaatin communities. These discussions have evolved into assessing whether an energy storage pilot project could be developed in a remote region of the distribution system serving Anwaatin communities and tested to determine reliability improvement and whether this approach could be used as a repeatable approach in other regions of the system.

More technical information is now available regarding this initiative. Hydro One's current technical assessment has focused on the three distribution feeder lines that serve the Nakina and Moosonee communities (referred to as Moosonee F1 and F3, and Nakina F2).

These assessments, included in Attachment 11, provide information regarding the following:

- the historical reliability of these feeders;
- three potential energy storage solutions that are in the process of evaluation;
- expected levels of costs of each solution; and
- the potential reliability improvement.

The assessments are continuing. Completion of all detailed engineering and financial viability review is targeted by September 30, 2018. Forecast investment for this new pilot project will not exceed $5 million. Government grants and funding may also provide a source of funds. One of the key objectives with this pilot project is assessing scalability to meet similar reliability concerns in other communities served by Hydro One.

At this time, issues affecting pilot project feasibility include, but are not limited to, the following:

- Installation of energy storage facilities on a radial line will result in the "islanding" of an area, with the consequence that during the outage, this load would be served by non-wires storage. This technical design and approach are not found on any other part of the Hydro One Distribution system and will require careful operational scrutiny.

- Estimated capital costs set out in the attached technical assessments are preliminary and subject to further review. Investment estimates depend on a variety of factors, including battery sizing, variability of load, and availability of government funding programs.

- Cost/benefit analysis of the potential reliability improvement must also be considered by a comparison to other potential ways to improve reliability, such as changes in vegetation management and prior transmission investments that have been made in the area.

d) Hydro One will continue to invest in its assets according to asset condition assessments without regard to preferences of specific shareholders.

Filed: 2018-06-15
EB-2017-0049
Exhibit I-6-Anwaatin-1
Attachment 11
Page 1 of 33

Nakina DS F2 & Moosonee DS F1/F3 Energy Storage Reliability Overview

June 15, 2018

Assumptions and Context

- HONI has recently explored Non-Wires Alternatives (NWA) to improve reliability to Anwaatin communities.
- Key issues associated with NWA include storage sizing, location, cost, and "islanding" operational concerns.
- This analysis is based on total community load. Variability in load may impact the battery backup duration to the community.
- Targeting critical loads for backup would reduce the battery size required, and hence the total cost.
- Cost estimates are based on informal vendor discussions, and publicly available information plus contingency due to remote access/unknown variables.
- Optimal location of the battery is in close proximity to the community to maximize the reliability benefit.

Feeder Supply to Anwaatin Communities

- Nakina DS F2 – supplies Aroland First Nations
- Moosonee DS F1 & F3 – supplies Mocreebec First Nations

Reliability Ranking of Supply Feeders

Ranking without Transmission Loss of Supply*

	SAIDI Ranking	SAIFI Ranking
Nakina DS F2	1988	2146
Moosonee DS F1	498	549
Moosonee DS F3	1134	1184

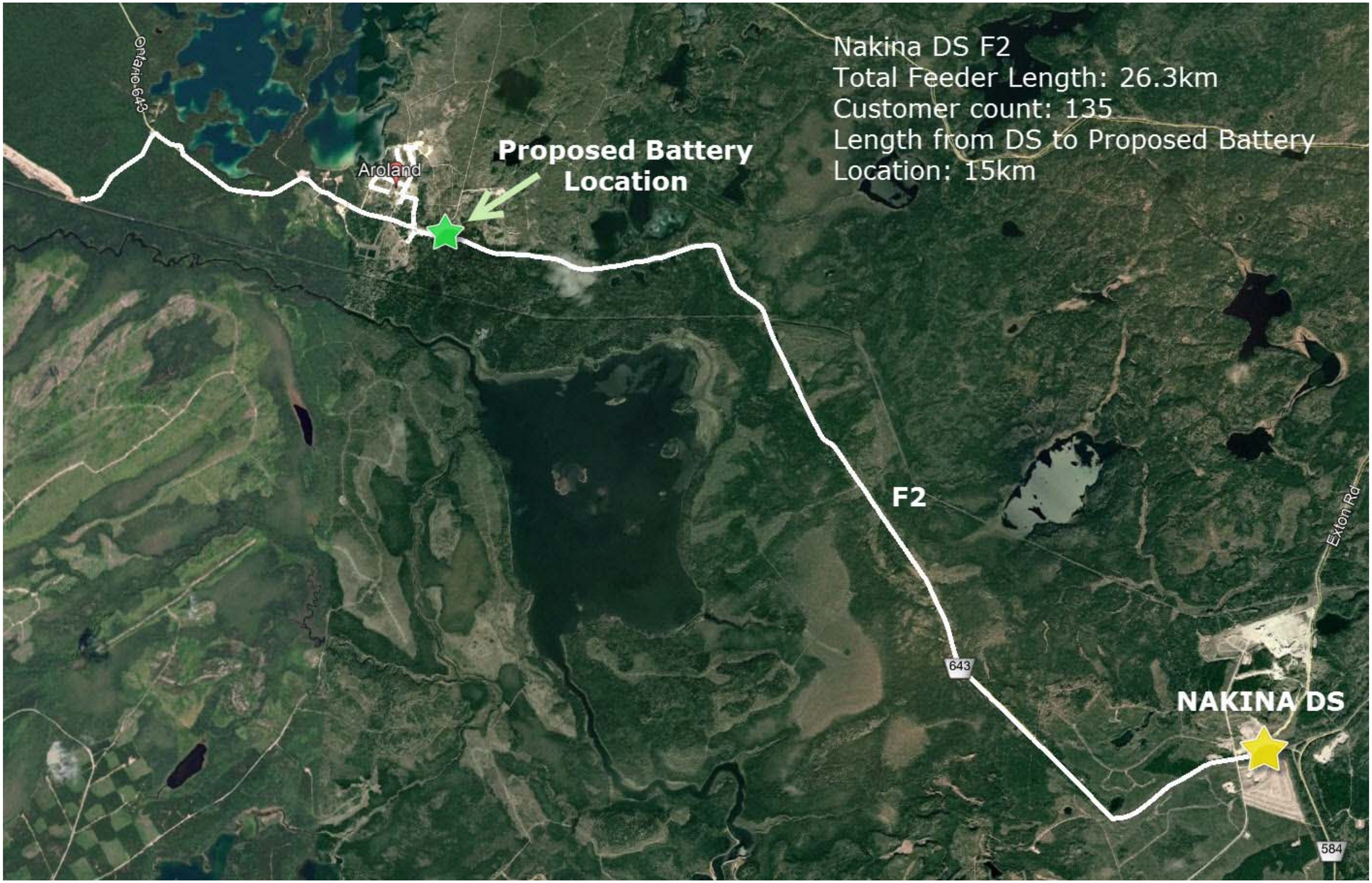
Ranking with Transmission Loss of Supply*

	SAIDI Ranking	SAIFI Ranking
Nakina DS F2	2022	2183
Moosonee DS F1	431	412
Moosonee DS F3	864	678

*Ranking based on 2015-2017 average data, out of approximately 3300 feeders. Feeder ranking is from worst to best, with "1" being the worst.

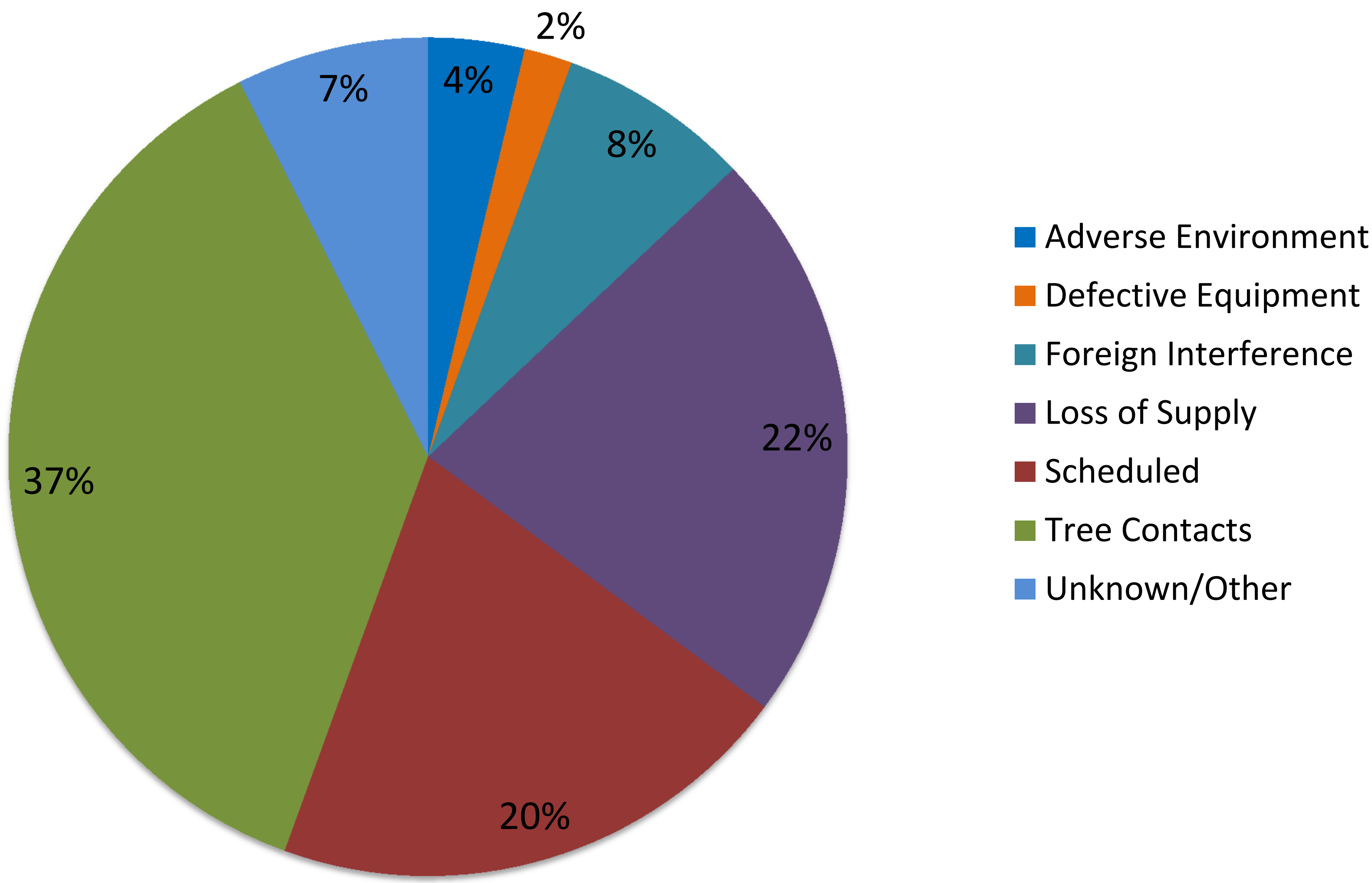
Nakina DS F2
Energy Storage
Reliability Overview

Nakina DS F2



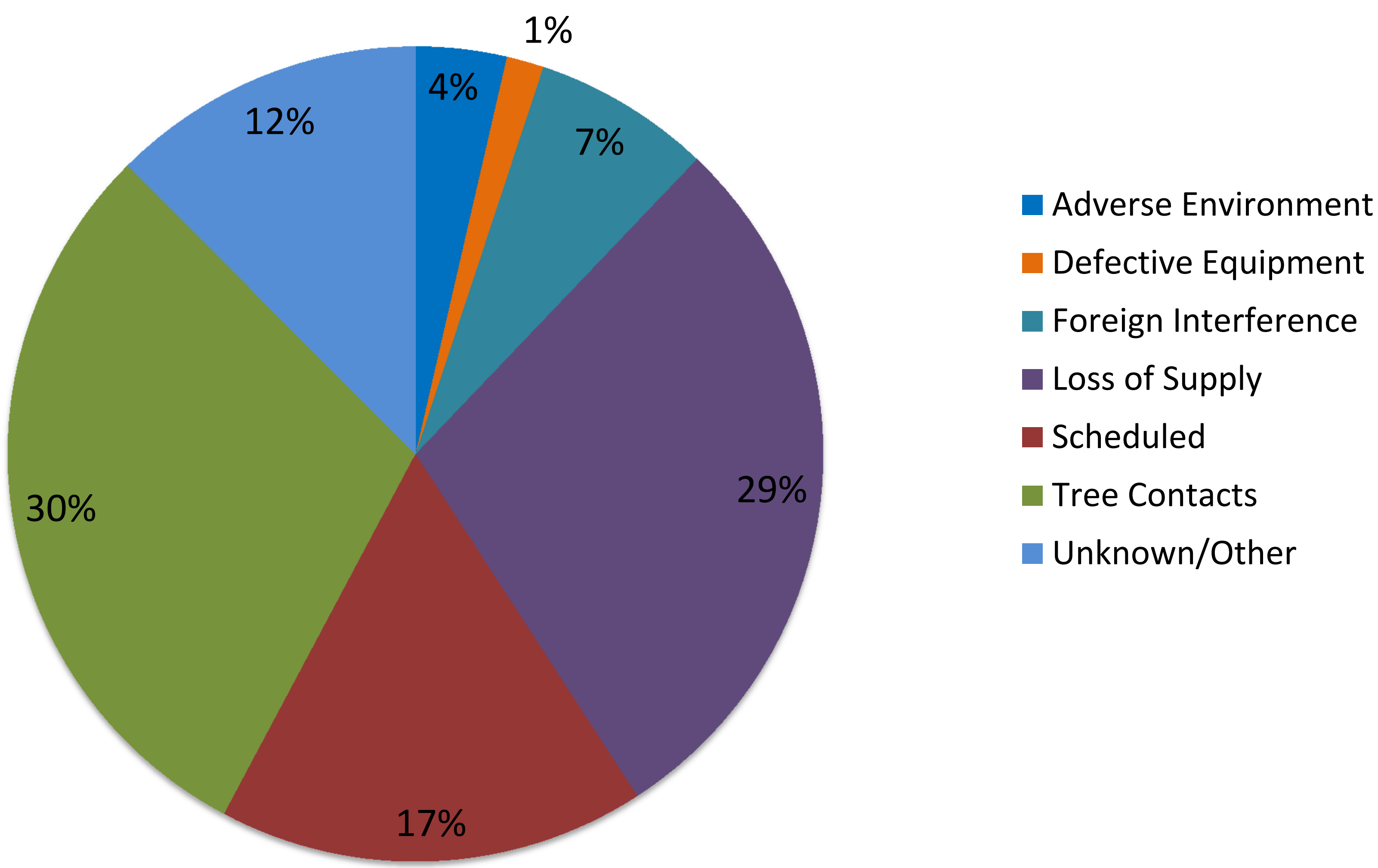
Nakina DS F2
Total Feeder Length: 26.3km
Customer count: 135
Length from DS to Proposed Battery Location: 15km
Proposed Battery Location
Aroland
Ontario 643
F2
643
NAKINA DS
Exton Rd
584

Nakina DS F2 - Frequency of Upstream Outages by Cause (5 years)



*Vegetation management will improve by 20-40% over the planning period.

Nakina DS F2 - Duration of Upstream Outages by Cause (5 Years)

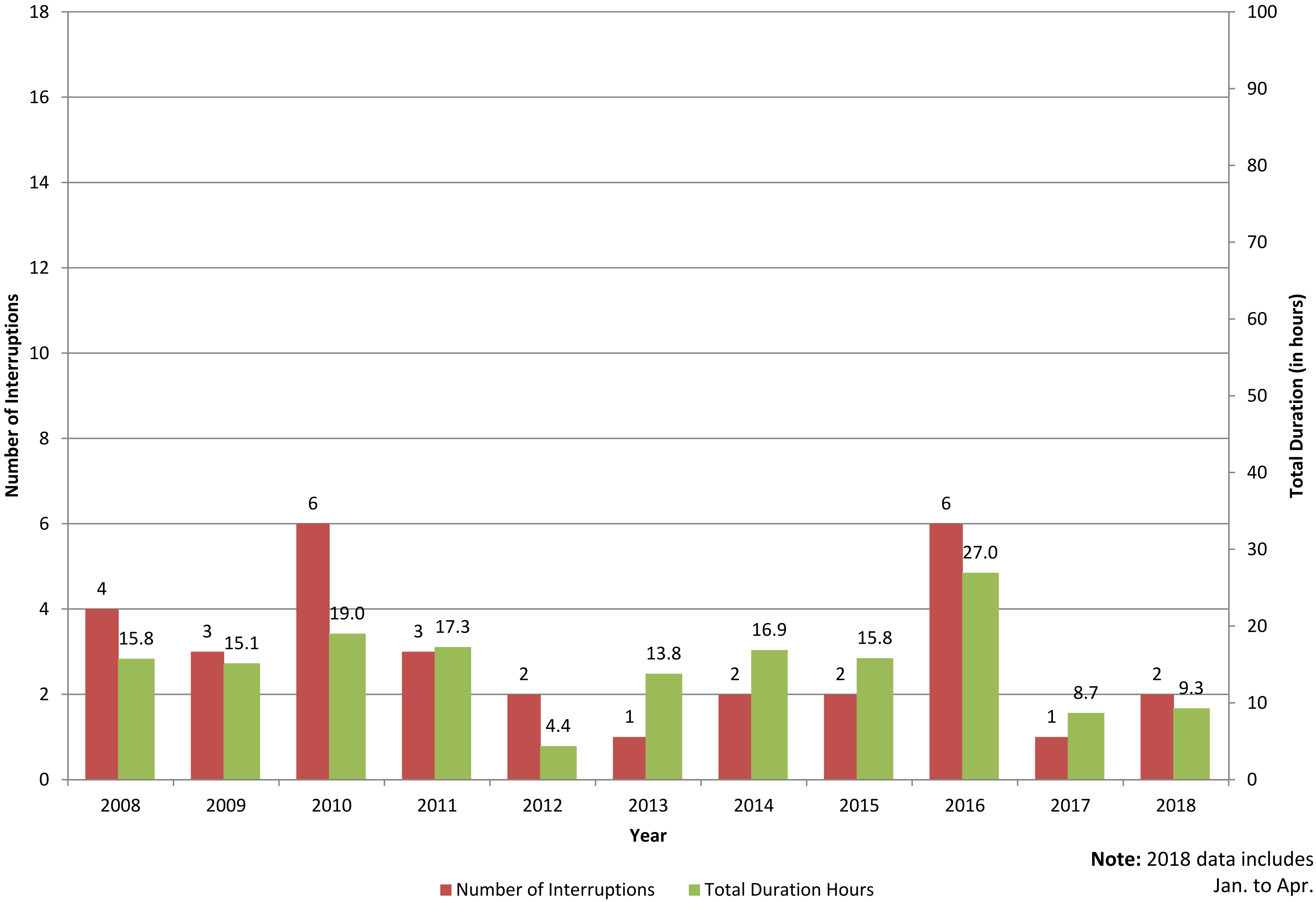


*Vegetation management will improve by 20-40% over the planning period.

Nakina DS F2 - Number and Total Duration of Outages by Year

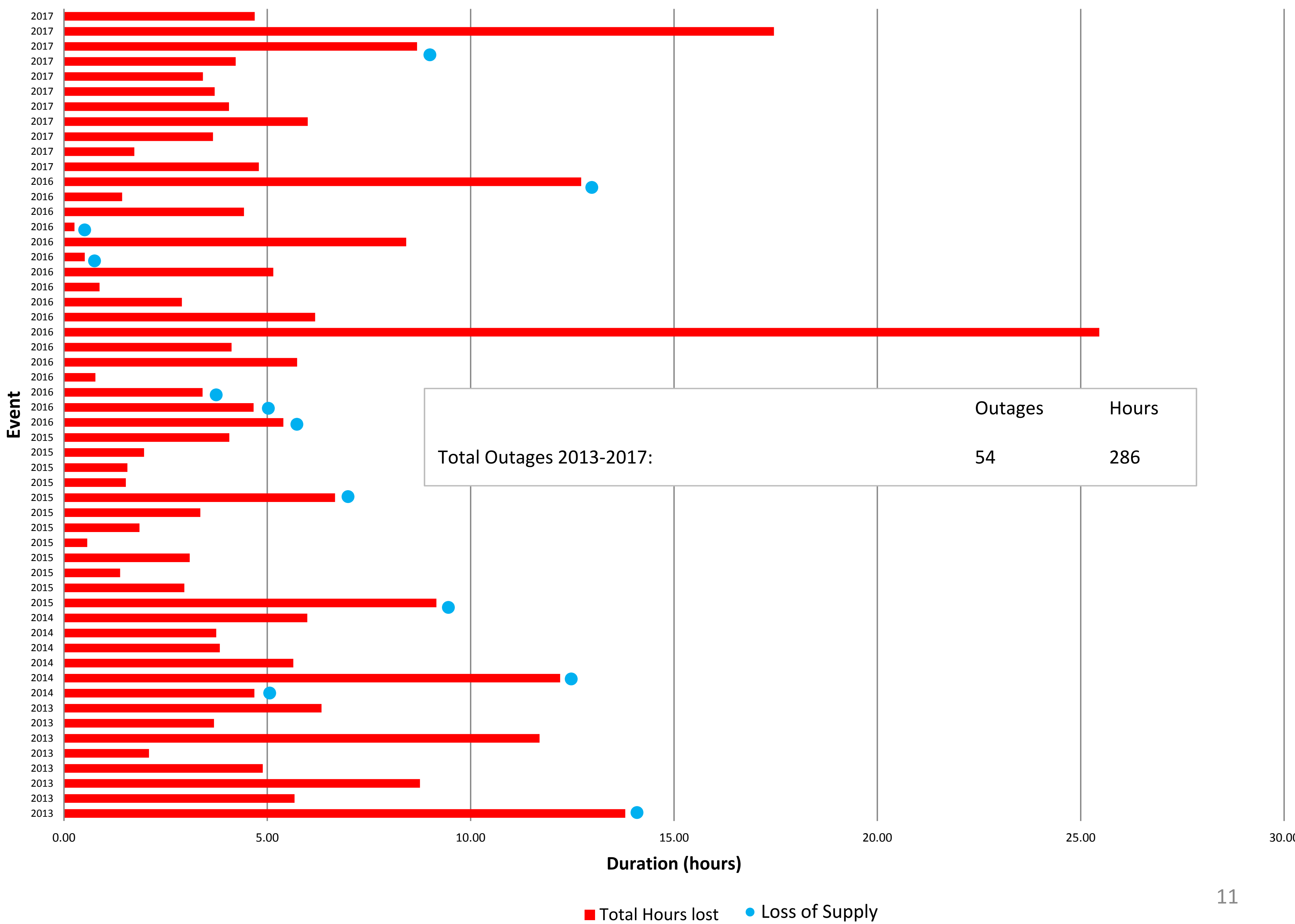
Year	Number of Outages	Total Duration of Outages (Hours)
2013	8	57
2014	6	36
2015	12	38
2016	17	92
2017	11	62

Transmission Loss of Supply Interruptions for Nakina DS over 10 Years

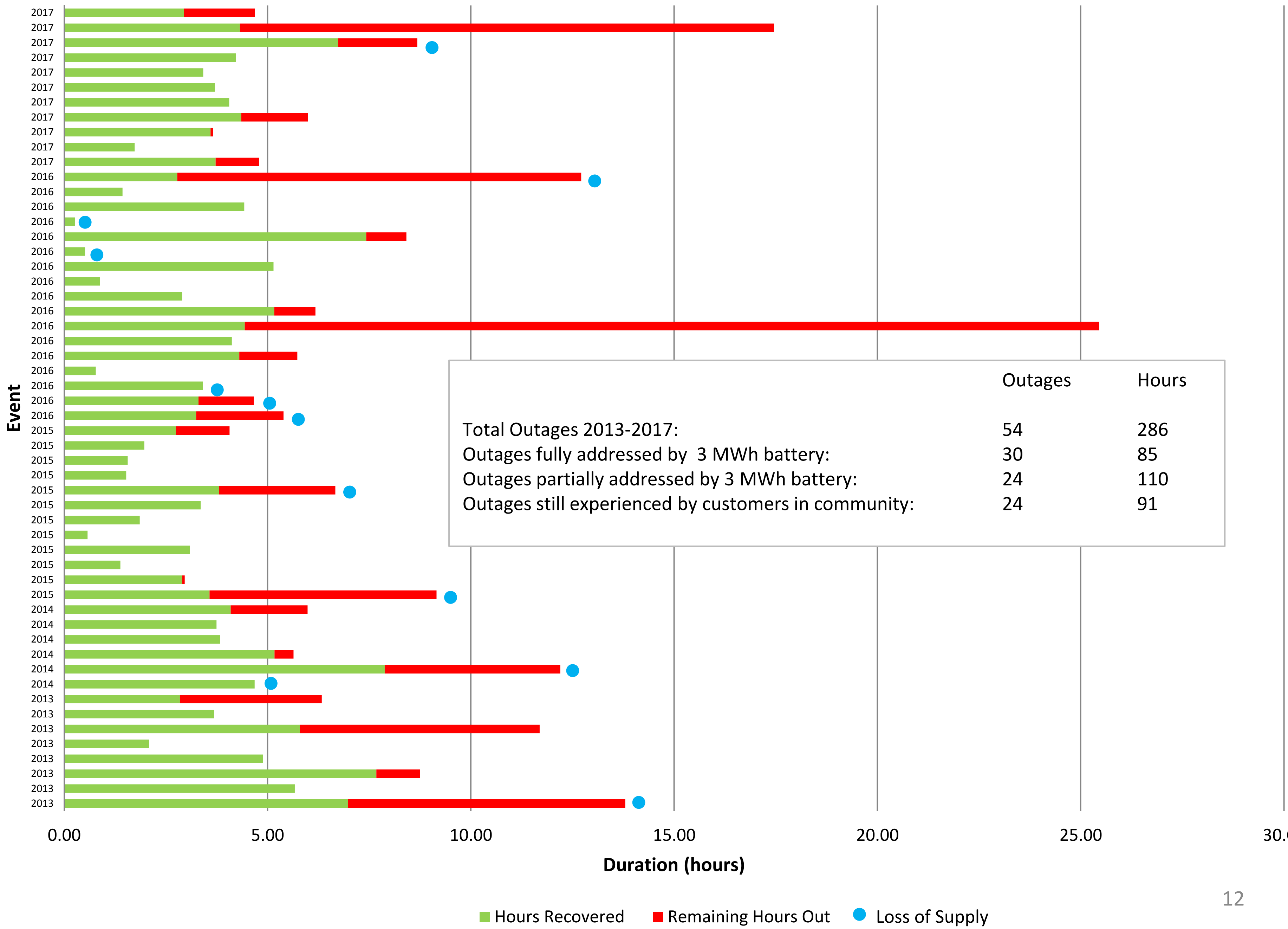


Note: 2018 data includes Jan. to Apr.

Nakina DS F2: Outages Experienced Over Last 5 Years

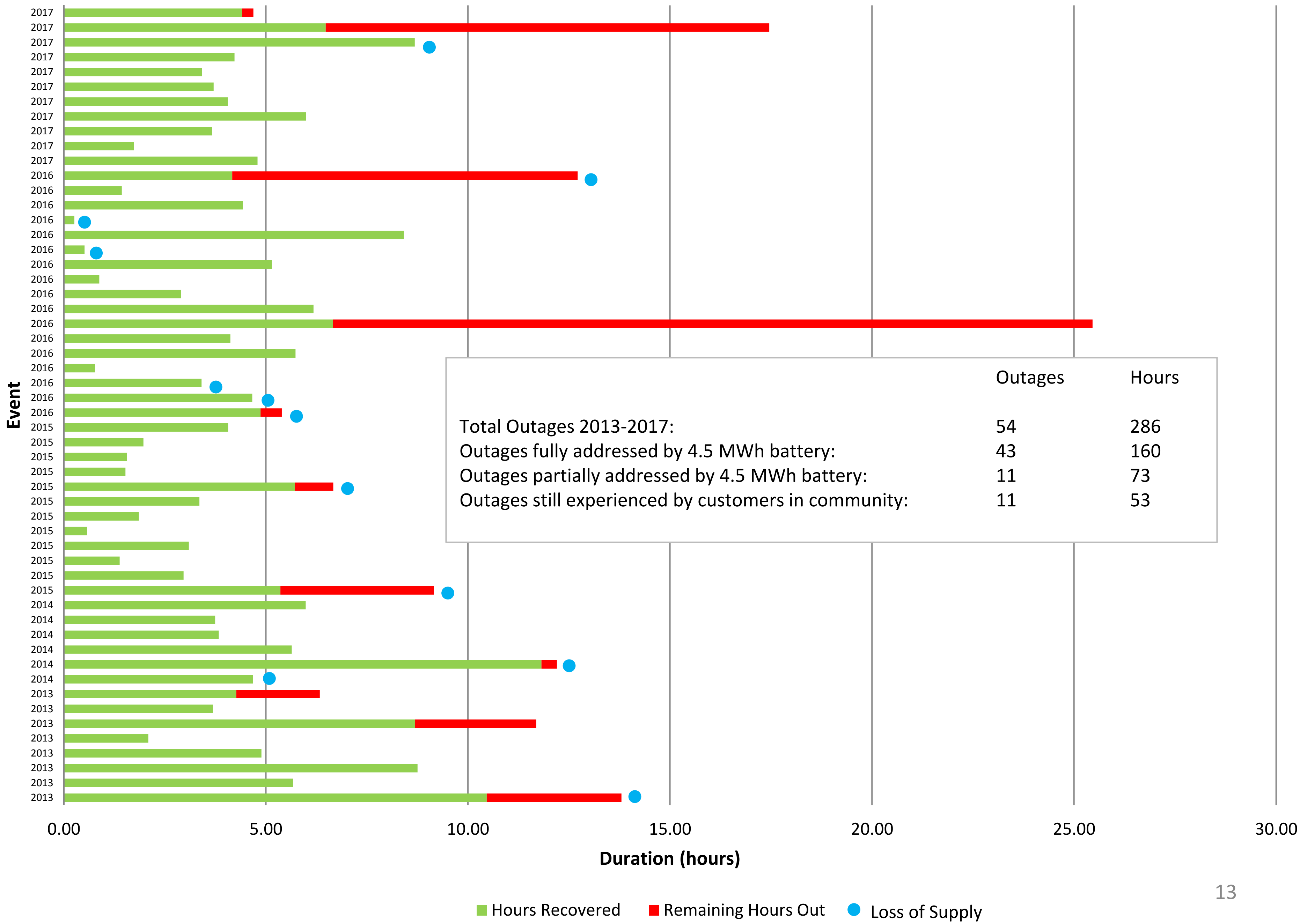


Nakina DS F2: Outage Impact with 1.5MW, 3MWh energy storage ($4.5M)

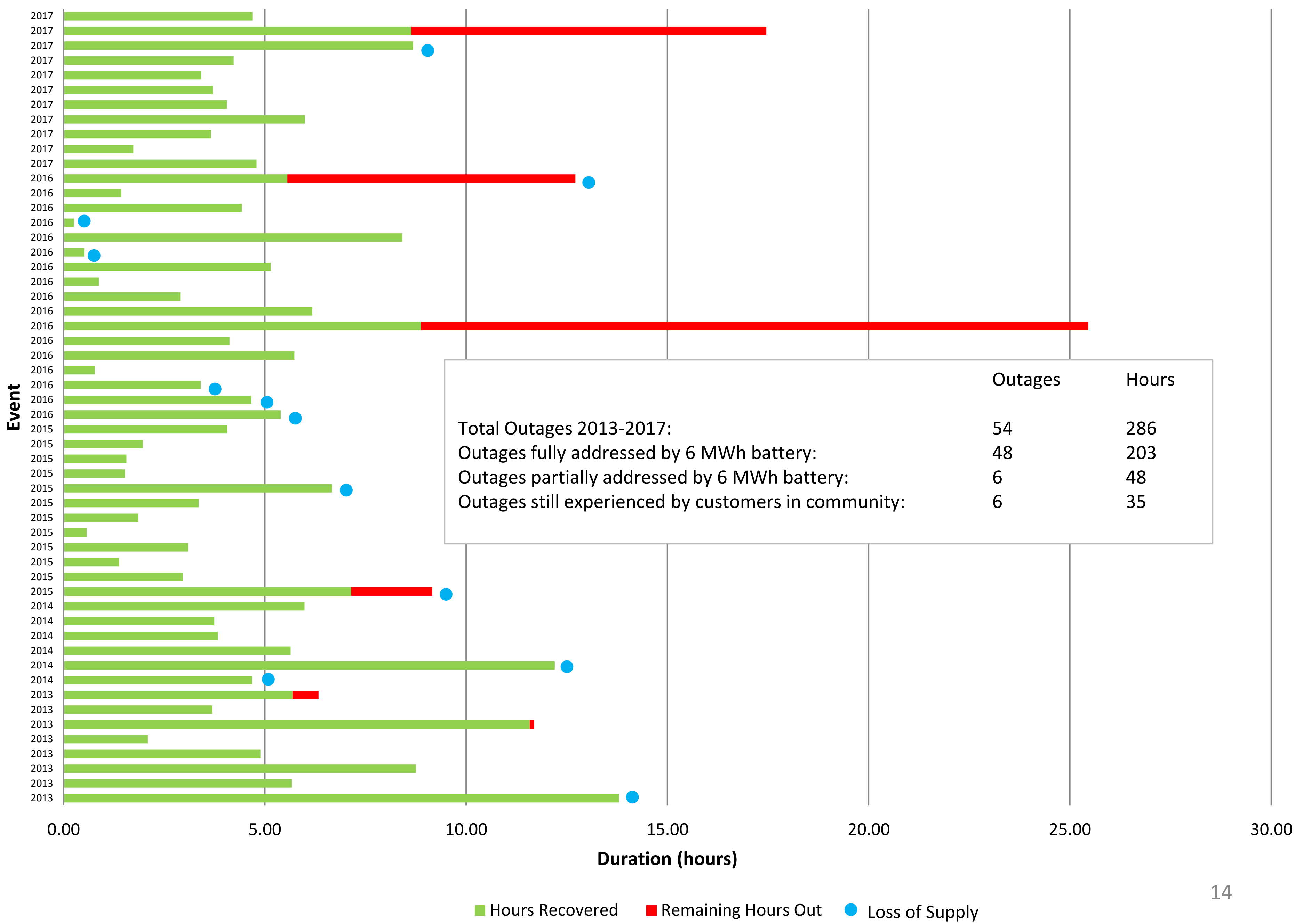


	Outages	Hours
Total Outages 2013-2017:	54	286
Outages fully addressed by 3 MWh battery:	30	85
Outages partially addressed by 3 MWh battery:	24	110
Outages still experienced by customers in community:	24	91

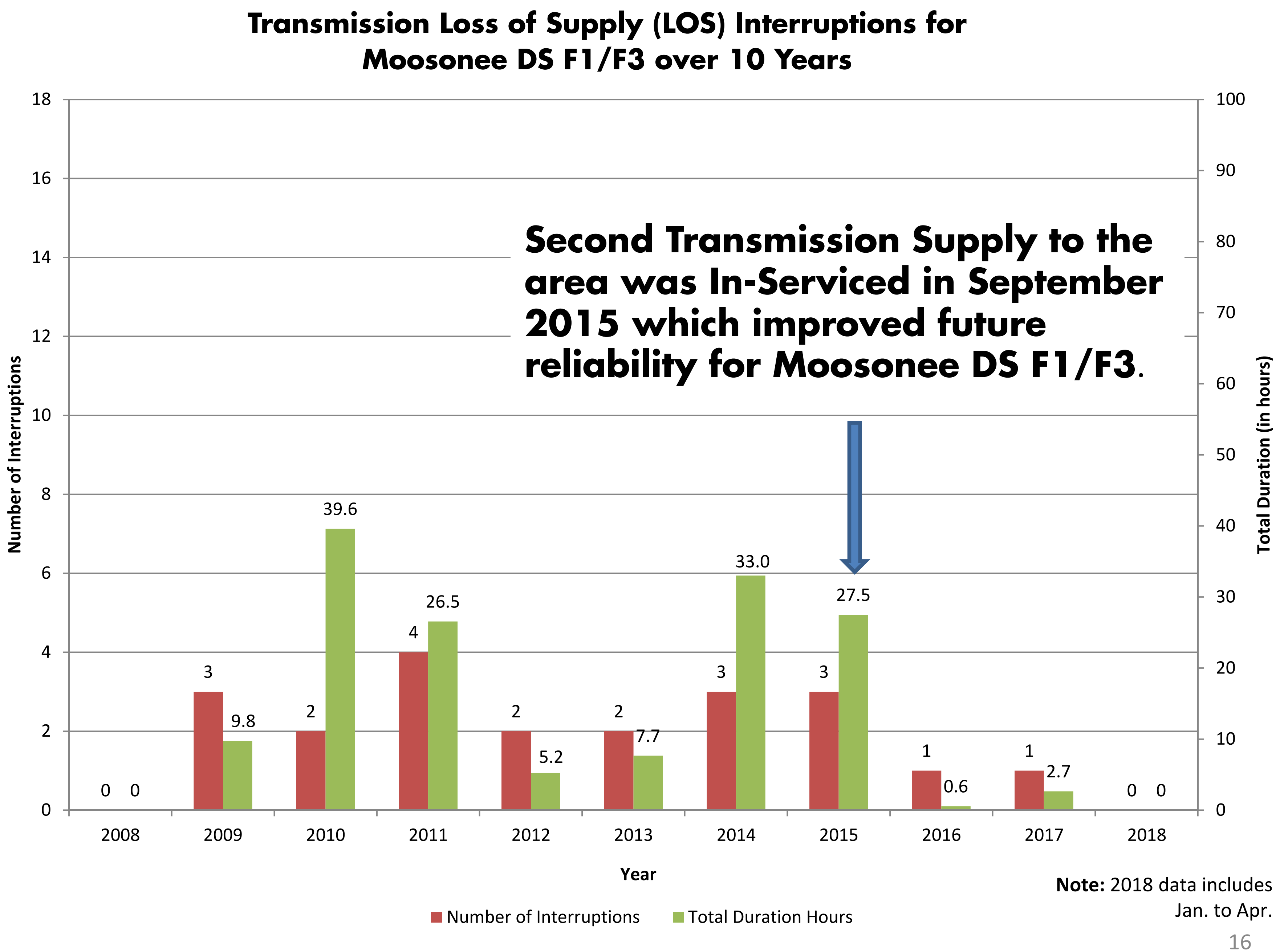
Nakina DS F2: Outage Impact with 1.5MW, 4.5MWh energy storage ($6.8M)



Nakina DS F2: Outage Impact with 1.5MW, 6MWh energy storage ($9M)

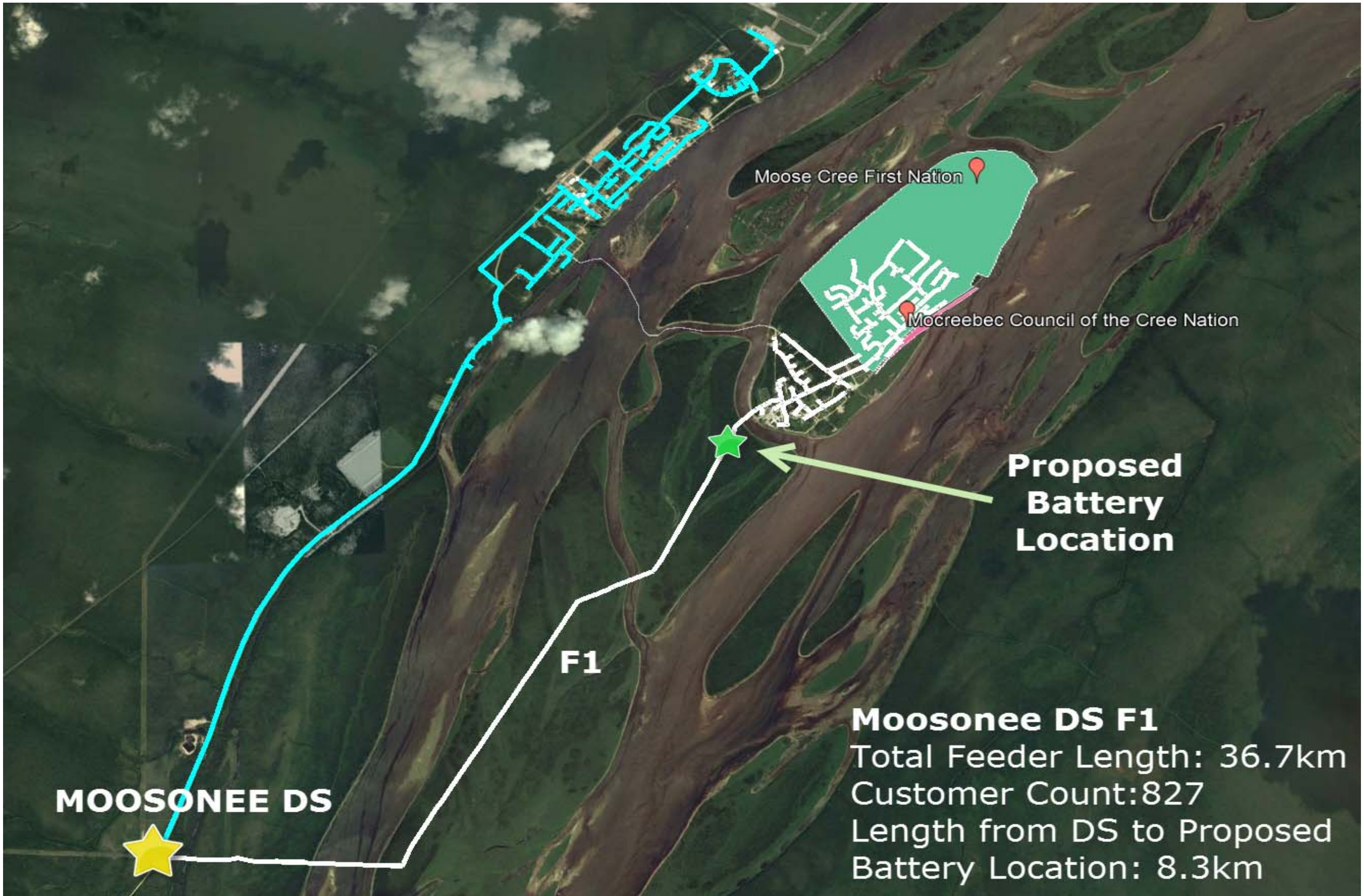


Moosonee DS F1/F3 Energy Storage Reliability Overview



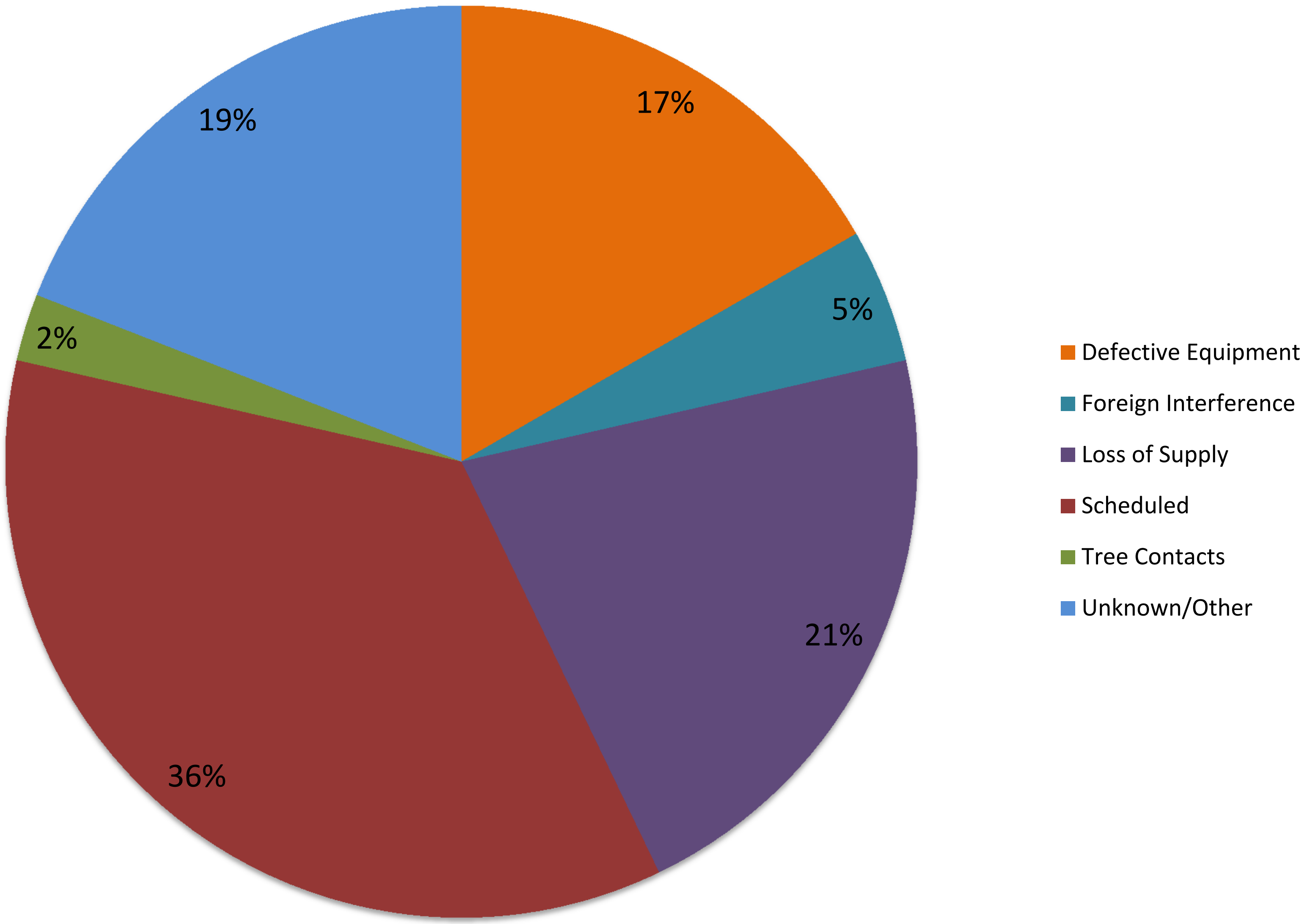
Transmission Loss of Supply (LOS) Interruptions for Moosonee DS F1/F3 over 10 Years
Second Transmission Supply to the area was In-Serviced in September 2015 which improved future reliability for Moosonee DS F1/F3.
Number of Interruptions
Total Duration (in hours)
Year
0 2 4 6 8 10 12 14 16 18
0 10 20 30 40 50 60 70 80 90 100
2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018
0 0
3 9.8
2 39.6
4 26.5
2 5.2
2 7.7
3 33.0
3 27.5
1 0.6
1 2.7
0 0
Number of Interruptions
Total Duration Hours
Note: 2018 data includes Jan. to Apr.
16

Moosonee DS F1



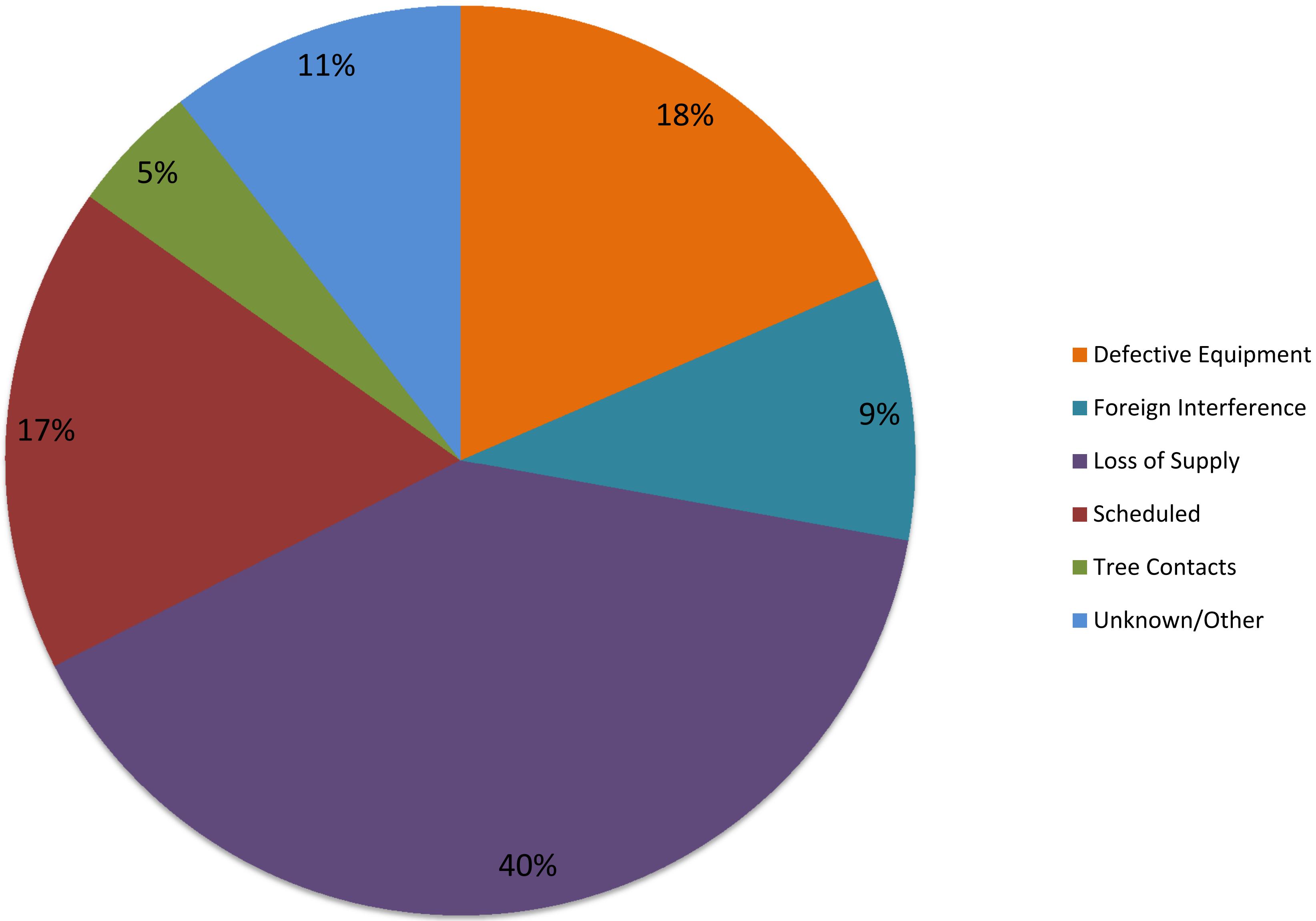
17

Moosonee DS F1: Frequency of Upstream Outages by Cause (5 years)



*Vegetation management will improve by 20-40% over the planning period.
** Reduction in frequency of Loss of Supply is expected due to upstream transmission investments.

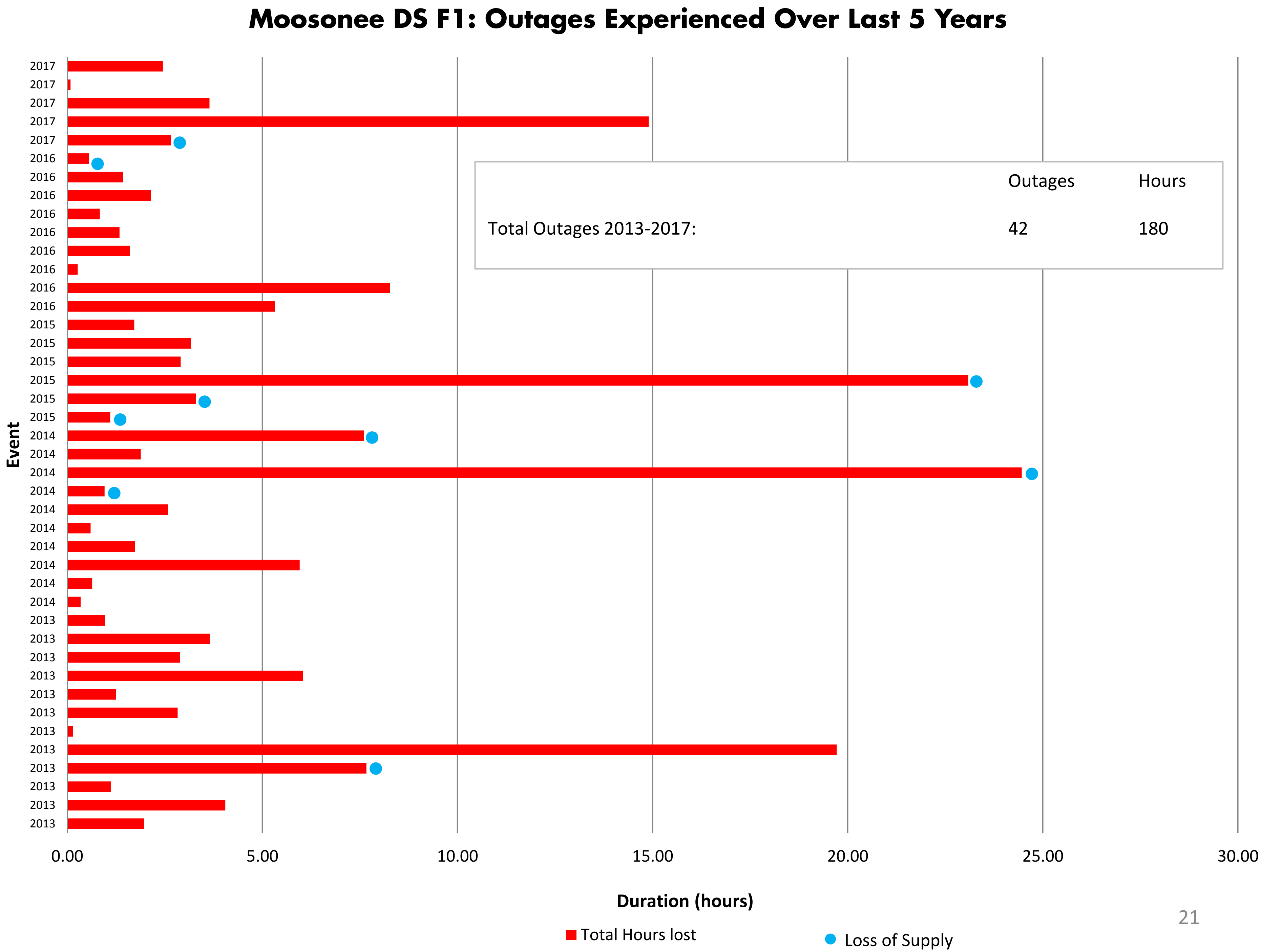
Moosonee DS F1: Duration of Upstream Outages by Cause (5 years)



*Vegetation management will improve by 20-40% over the planning period.
** Reduction in frequency of Loss of Supply is expected due to upstream transmission investments.

Moosonee DS F1 - Number and Total Duration of Outages by Year

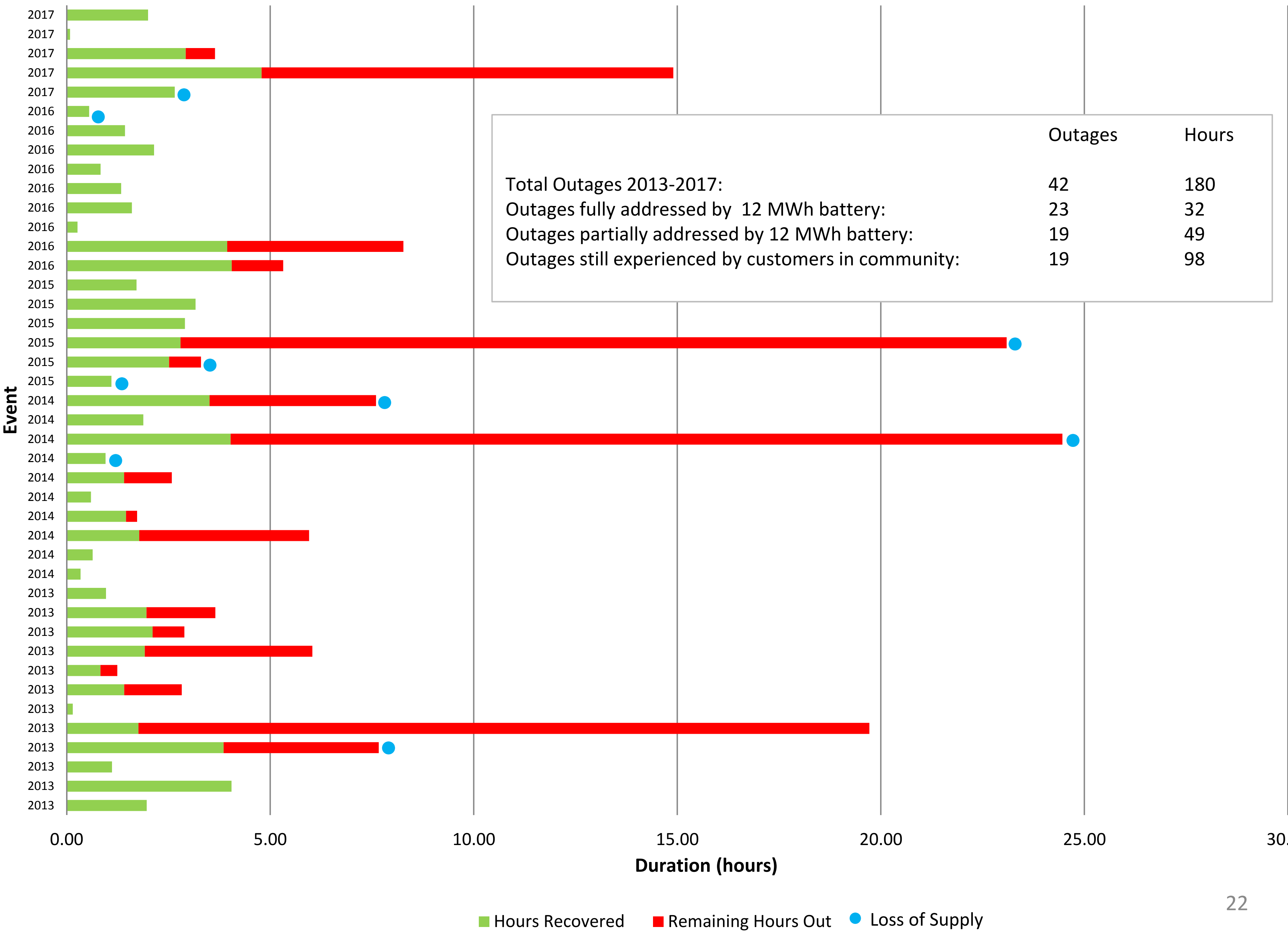
Year	Number of Outages	Total Duration of Outages (Hours)
2013	12	52
2014	10	47
2015	6	35
2016	9	22
2017	5	24

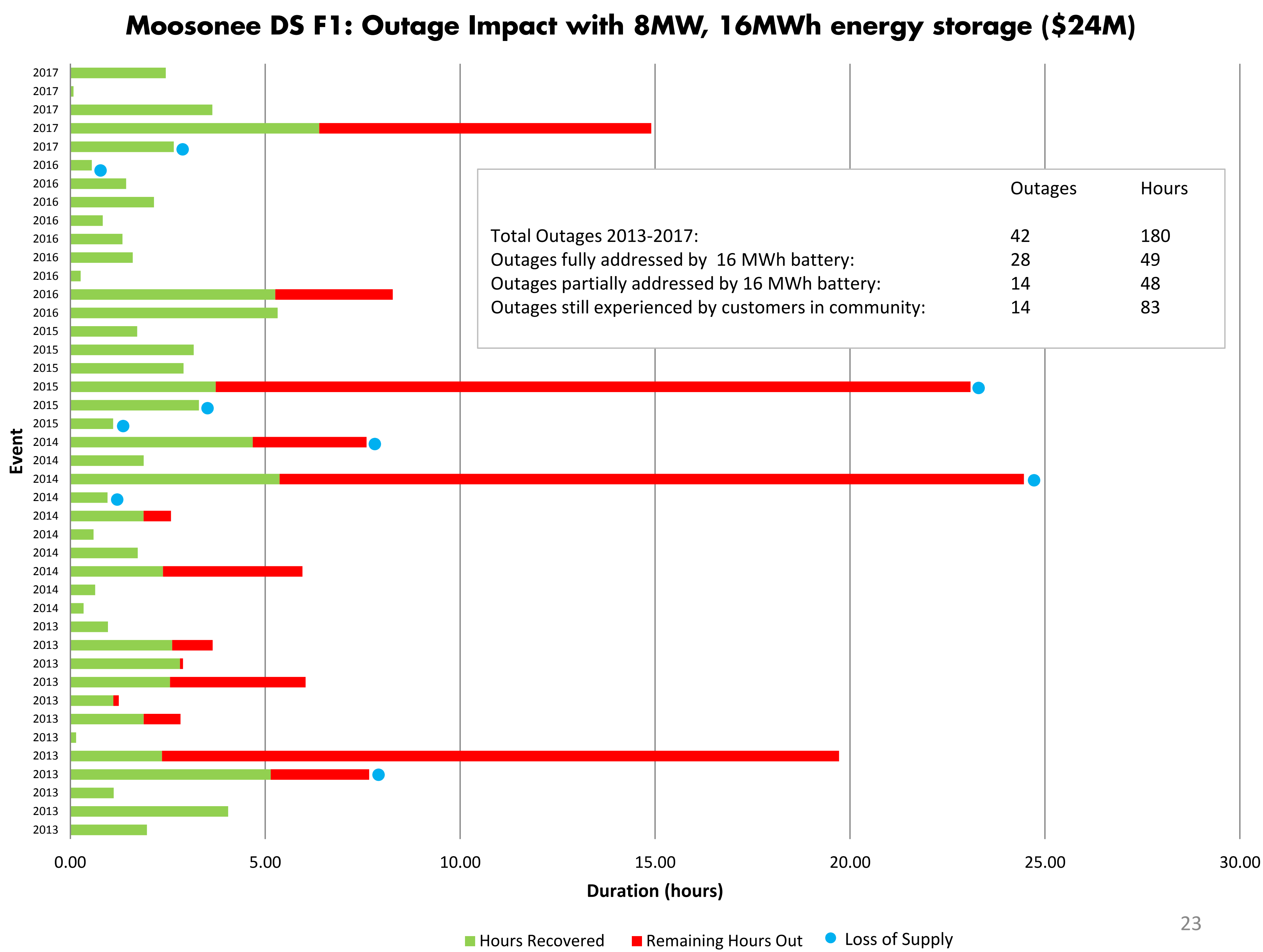


Moosonee DS F1: Outages Experienced Over Last 5 Years
Outages
Hours
Total Outages 2013-2017:
42
180
Event
2017
2016
2015
2014
2013
0.00
5.00
10.00
15.00
20.00
25.00
30.00
Duration (hours)
Total Hours lost
Loss of Supply

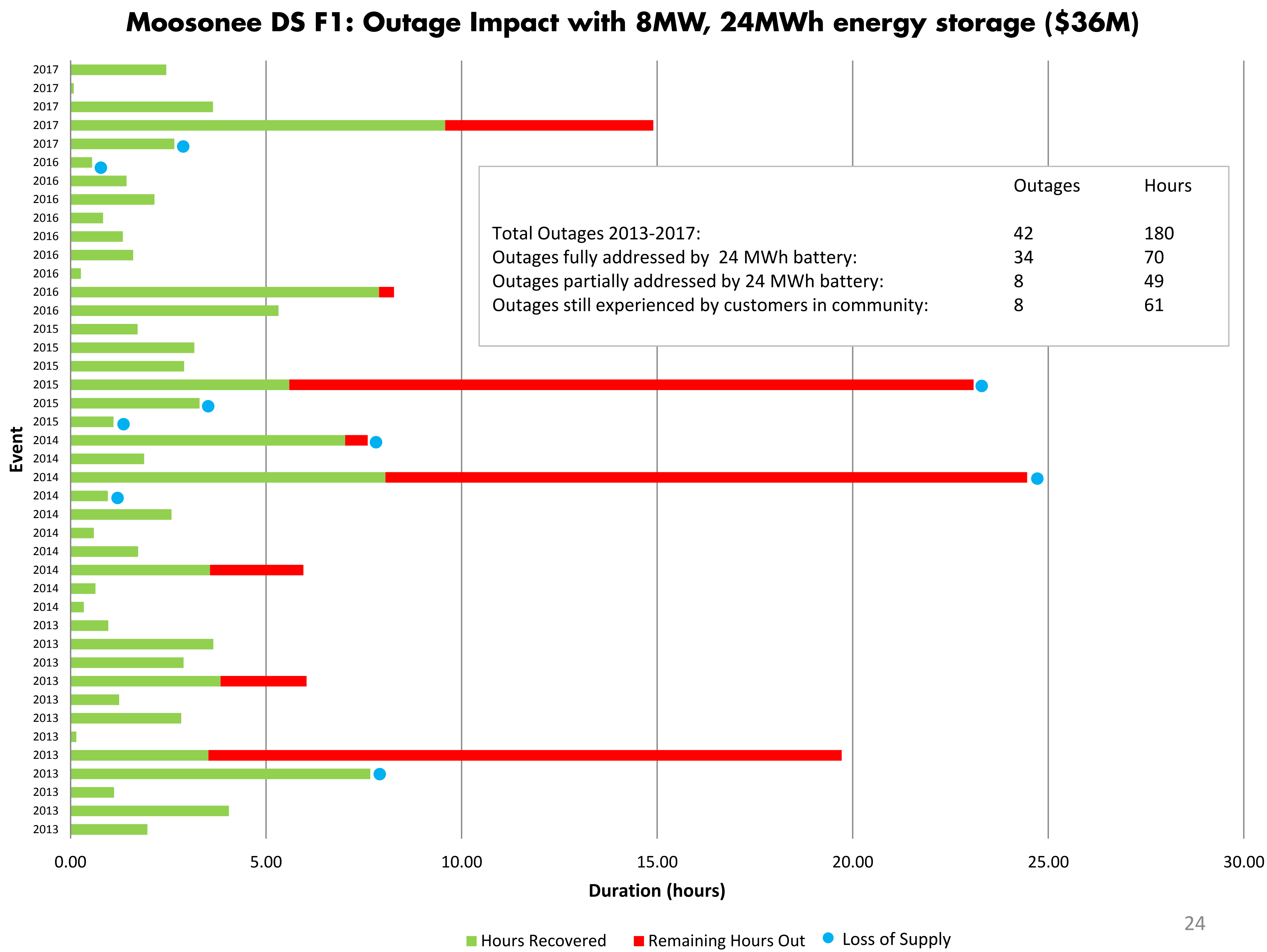
21

Moosonee DS F1: Outage Impact with 8MW, 12MWh energy storage ($18M)



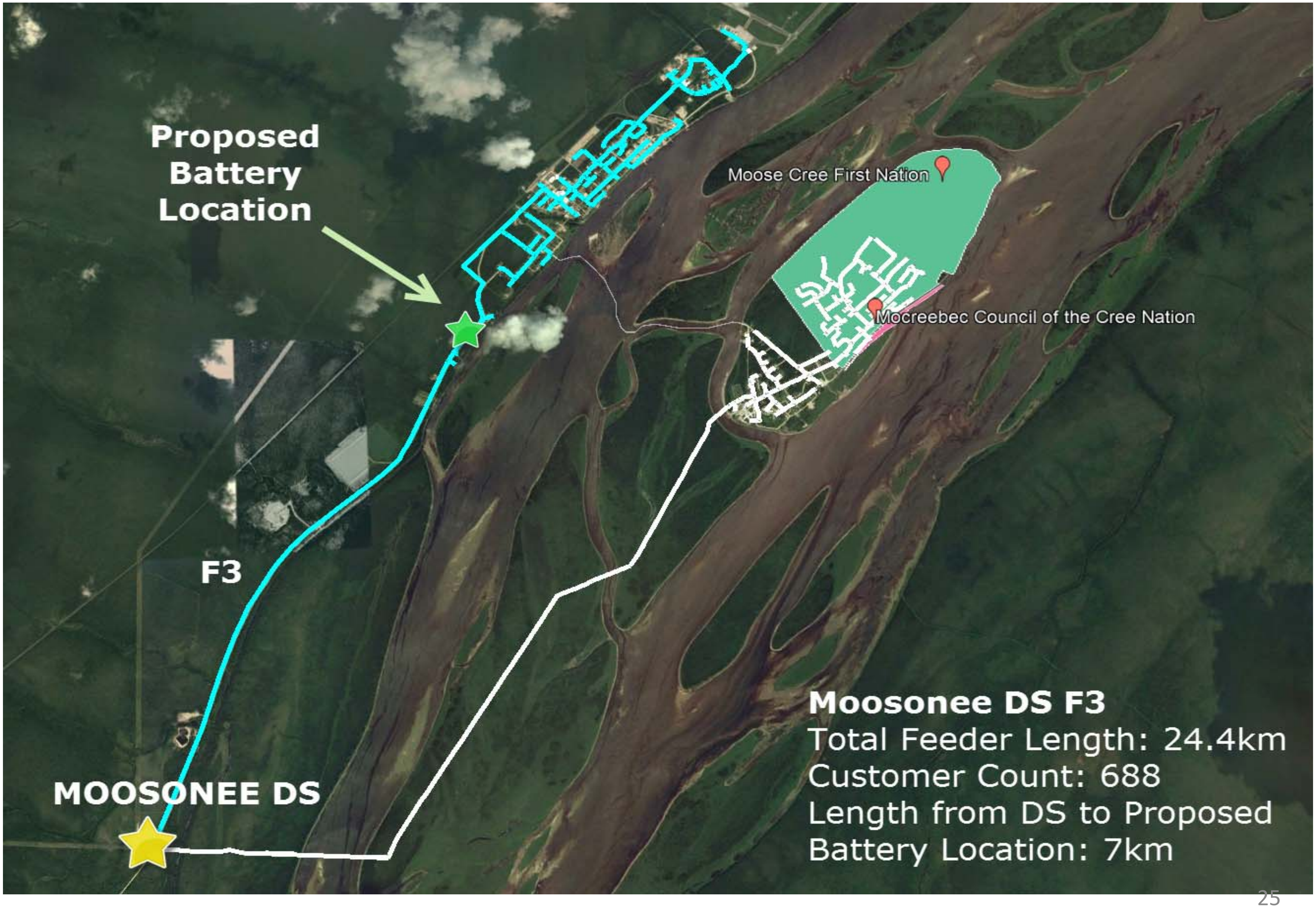


Moosonee DS F1: Outage Impact with 8MW, 16MWh energy storage ($24M)
Event
2017
2016
2015
2014
2013
Outages
Hours
Total Outages 2013-2017: 42 180
Outages fully addressed by 16 MWh battery: 28 49
Outages partially addressed by 16 MWh battery: 14 48
Outages still experienced by customers in community: 14 83
0.00
5.00
10.00
15.00
20.00
25.00
30.00
Duration (hours)
Hours Recovered
Remaining Hours Out
Loss of Supply
23


Moosonee DS F1: Outage Impact with 8MW, 24MWh energy storage ($36M)
Outages
Hours
Total Outages 2013-2017: 42 180
Outages fully addressed by 24 MWh battery: 34 70
Outages partially addressed by 24 MWh battery: 8 49
Outages still experienced by customers in community: 8 61
Event
Duration (hours)
0.00
5.00
10.00
15.00
20.00
25.00
30.00
Hours Recovered
Remaining Hours Out
Loss of Supply

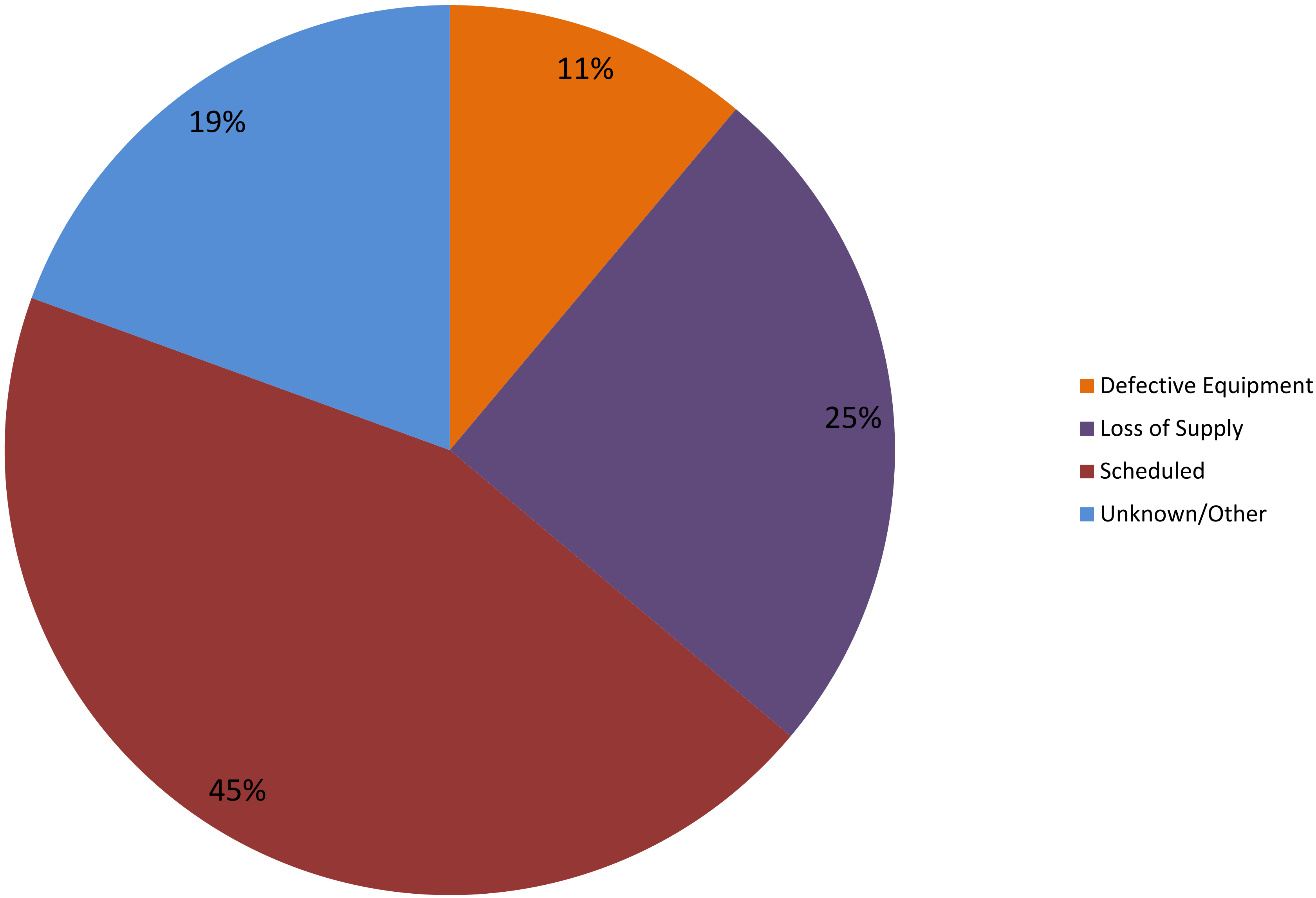
24

Moosonee DS F3



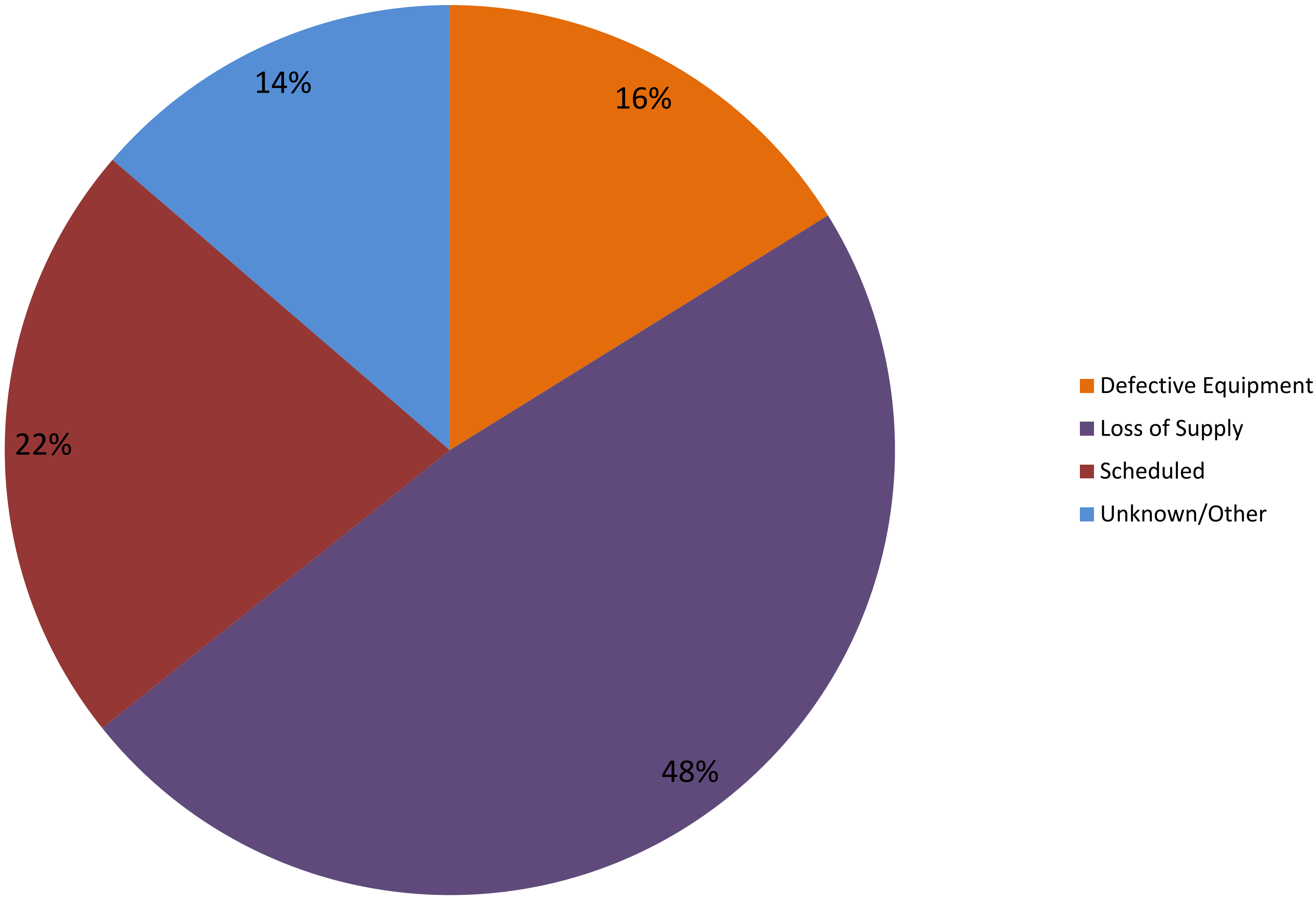
25

Moosonee DS F3: Frequency of Upstream Outages by Cause (5 years)



* Reduction in frequency of Loss of Supply is expected due to upstream transmission investments.

Moosonee DS F3: Duration of Upstream Outages by Cause (5 years)

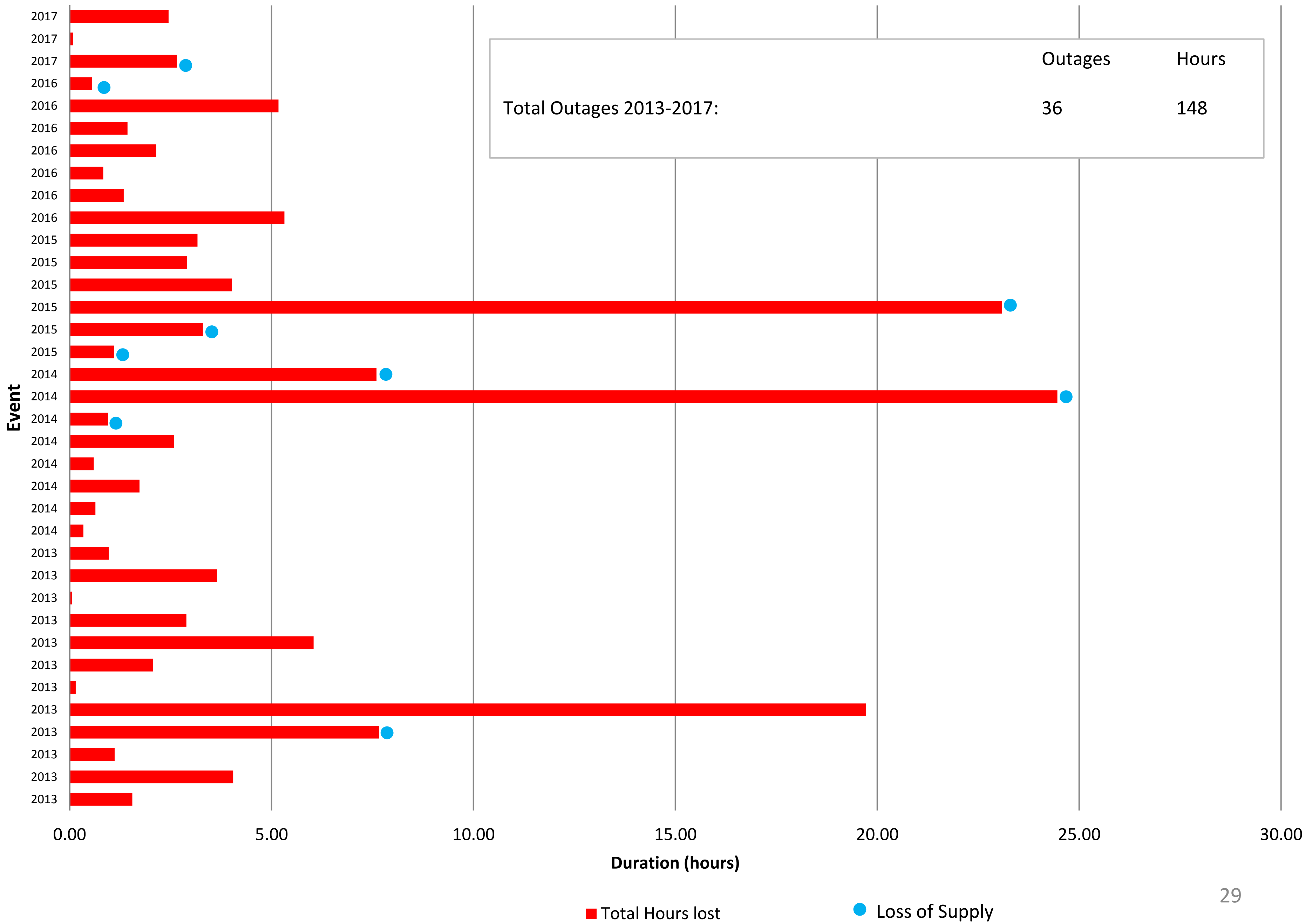


* Reduction in frequency of Loss of Supply is expected due to upstream transmission investments.

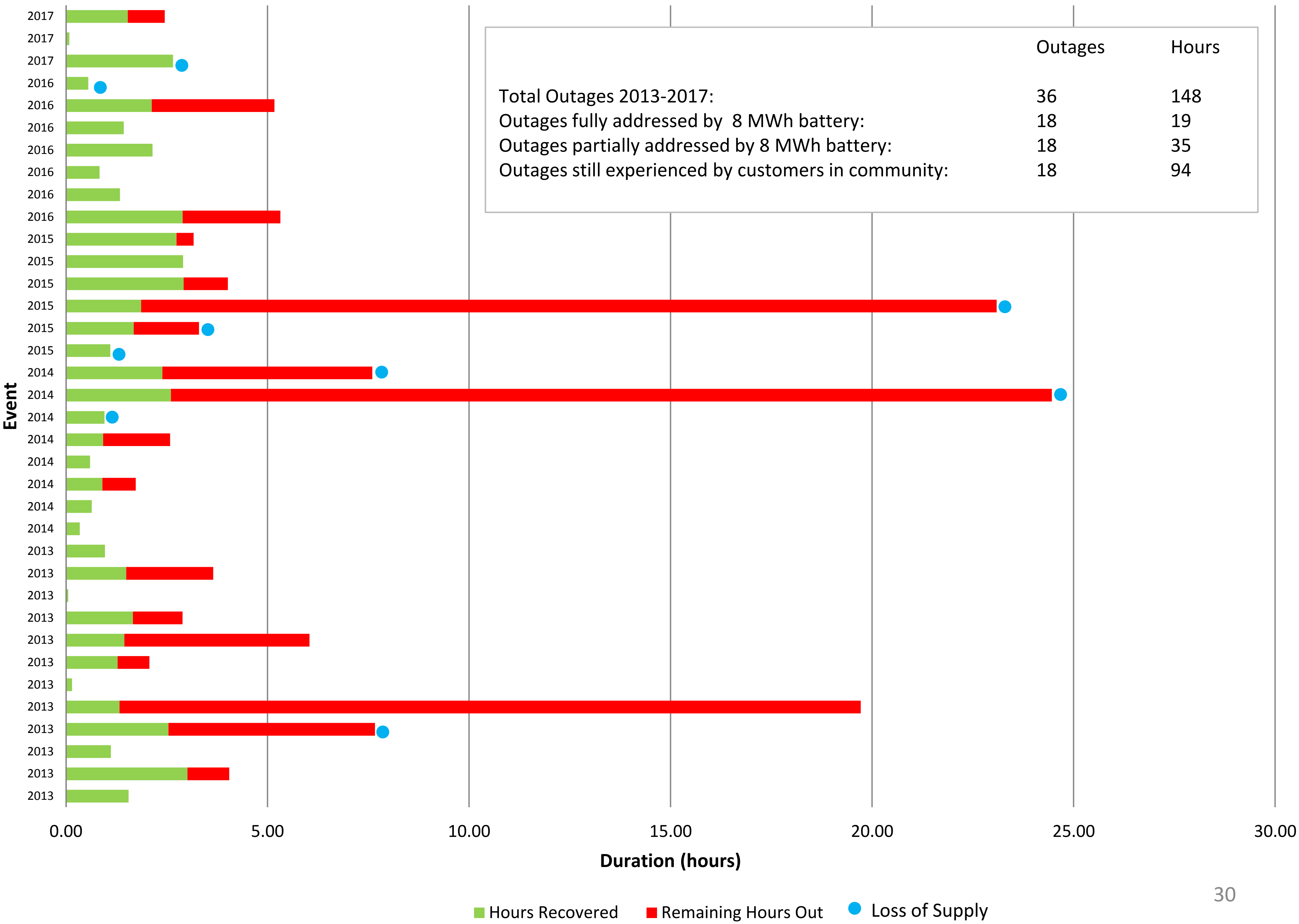
Moosonee DS F3: Number and Total Duration of Outages by Year

Year	Number of Outages	Total Duration of Outages (Hours)
2013	12	50
2014	8	39
2015	6	38
2016	7	17
2017	3	5

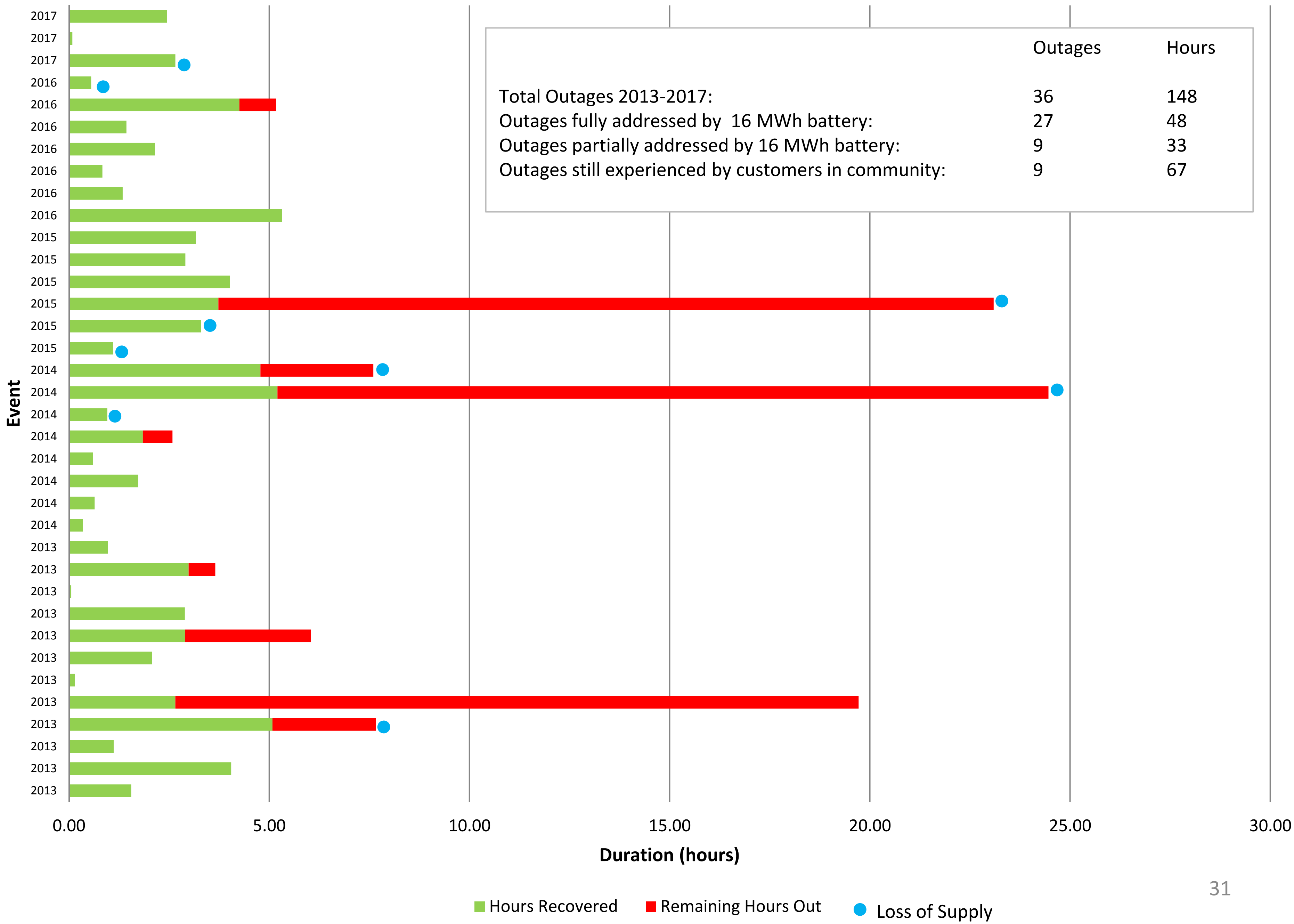
Moosonee DS F3: Outages Experienced Over Last 5 Years



Moosonee DS F3: Outage Impact with 8MW, 8MWh energy storage ($12M)

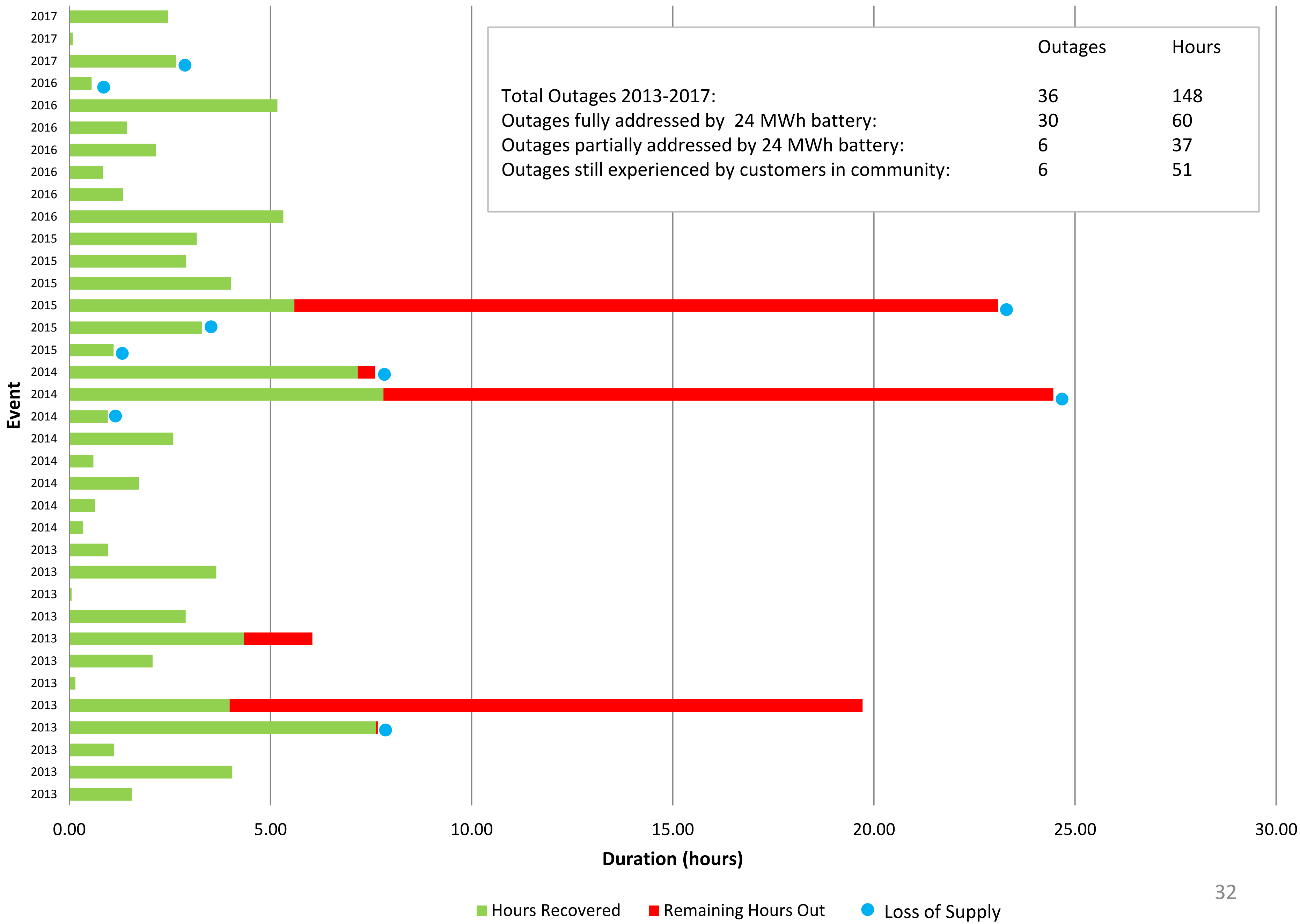


Moosonee DS F3: Outage Impact with 8MW, 16MWh energy storage ($24M)



31

Moosonee DS F3: Outage Impact with 8MW, 24MWh energy storage ($36M)



Investment Prioritization

- Retention of an experienced storage and engineering partner is underway.
- The detailed engineering and financial viability review is targeted by September 30, 2018.
- There may be additional value due to scalability.
- Pilot project funding sourced through redirection ($5M) and may be offset or augmented by government funding programs.

TAB 5

DEMARCO ALLAN LLP

Lisa (Elisabeth) DeMarco
Senior Partner
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Toronto, ON M5R 2E1
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lisa@demarcoallan.com

June 15, 2018

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: EB-2017-0335
Anwaatin Inc. Motion to Review and Vary Ontario Energy Board Decision in EB-2016-0160 ("Anwaatin MRV")

We are counsel to Anwaatin Inc. (**Anwaatin**) in relation to the Anwaatin MRV.

Further to our prior correspondence in relation to the Anwaatin MRV, we hereby submit the attached Settlement Proposal for the Panel's review and consideration. Anwaatin and Hydro One Networks Inc. have worked diligently to reach agreement on several issues, each of which has been fully settled as described in the Settlement Proposal. It is our understanding, subject to their additional communications with the Board, that VECC and SEC, the intervenors in the Anwaatin MRV, do not oppose the contents of the Settlement Proposal.

Sincerely,

Lisa (Elisabeth) DeMarco

cc: Intervenors
Jennifer Lea, OEB
Harold Thiessen, OEB
Gordon Nettleton, McCarthy Tétrault LLP

SETTLEMENT PROPOSAL

ANWAATIN INC.

Motion to Review and Vary the Ontario Energy Board's Decision
on Hydro One Network Inc.'s Transmission Rates in EB-2016-0160

EB-2017-0335

June 15, 2018

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Anwaatin Inc.
EB-2017-0335

SETTLEMENT PROPOSAL

A. PREAMBLE

This Settlement Proposal is filed with the Ontario Energy Board (the "**OEB"**) in connection with the Anwaatin Inc. ("**Anwaatin"**) Motion to Review and Vary the Ontario Energy Board's Decision on Hydro One Networks Inc.'s ("**HONI"**) Transmission Rates in EB-2016-0160 (the "**Decision"**) through the EB-2017-0335 proceeding (the "**Anwaatin MRV"**). It follows settlement discussions that took place after the Anwaatin MRV was argued and before the OEB rendered a decision in the Anwaatin MRV. The settlement discussions were predominantly between Anwaatin and HONI, with limited involvement of a distributed energy resource developer, Abundant Solar Inc. ("**Abundant"**), and the two intervenors in the Anwaatin MRV, (Schools Energy Coalition "**SEC**") and Vulnerable Energy Consumers Coalition "**VECC**") in a manner that was guided by the process contemplated in the OEB''s Practice Direction on Settlement Conferences, as amended (the "**Practice Direction**"). OEB staff were also informed of the settlement discussions, but in accordance with the Practice Direction OEB Staff is neither a Party nor a signatory to this Settlement Proposal. Nonetheless, OEB Staff who were apprised of the developments in and around the settlement discussions are bound by the same confidentiality provisions that apply to all of the above-mentioned Parties and entities. The communities Anwaatin represents for the Anwaatin MRV and this Settlement Proposal ("**the Anwaatin First Nations**") include Aroland First Nation, MoCreebec Eeyoud, and Waaskiinaysay Ziibi Inc. Development Corporation ("**WZI**"), an economic development corporation representing five First Nations in the Lake Nipigon watershed: Animbiigoo Zaagiigan Anishinaabek, Bingwi Neyaashi Anishinaabek, Biinjitiwaabik Zaaging Anishinaabek. Red Rock Indian Band, and Whitesand First Nation.

This Settlement Proposal is subject to the following conditions subsequent:

(i) Acceptance of the Settlement Proposal by the OEB in its entirety, and in a manner that allows for implementation of its terms;

(ii) The Pilot Project satisfies the OEB and Ministry of Energy's Impact Assessment Requirements:

   a. System Impact Assessment conducted by the IESO; and

   b. Connection Impact Assessment conducted by HONI.

(iii) Obtaining any approvals required by Abundant and Anwaatin/Anwaatin First Nations, if any, regarding the repurposing of existing FIT contracts if included or required to facilitate reliability as part of the Pilot Project.

(iv) Decisions made by HONI to proceed with Phase 1 and 2 investments as described in Paragraph 1.5(c) below.

(collectively, the "**Conditions Subsequent**").

Unless amended on the written consent of Anwaatin and HONI, all Conditions Subsequent must be fulfilled by no later than December 31, 2021, failing which this Settlement Proposal is null and void and of no further effect.

In entering this agreement, the Parties understand and agree that, pursuant to the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B) (the "Act") the OEB has the exclusive initial jurisdiction with respect to the interpretation and enforcement of the terms hereof.

B. DESCRIPTION OF SETTLEMENT

1.1 The Parties

Anwaatin and HONI were the central parties to the Anwaatin MRV and are the signatories to this Settlement ("**Parties**"). Two other interveners participated in the Anwaatin MRV in a limited manner. SEC intervened in the Anwaatin MRV for the limited purpose of requesting that any cost consequences to the Decision be reviewed. VECC intervened in the Anwaatin MRV in support of Anwaatin. Abundant was involved in the settlement discussions in order to ensure that the proposed solutions were technically feasible and able to be implemented in a timely manner.

1.2 Confidentiality

The Parties agree that the settlement discussions shall be subject to the rules relating to confidentiality and privilege contained in the Practice Direction. The Parties acknowledge that confidentiality in that context does not have the same meaning as confidentiality in the OEB's Practice Direction on Confidential Filings, and the rules of that latter document do not apply. The Parties interpret the Practice Direction to mean that the documents and other information provided, the discussion of each issue, any offers and counter-offers, and the negotiations leading to settlement of each issue during the course of the settlement discussions are strictly confidential between the Parties and were undertaken on a without prejudice basis. None of the foregoing settlement discussions and processes leading to this Settlement Proposal are admissible as evidence in this or any other proceeding, or otherwise, except where the filing of such settlement information is necessary to implement the Settlement Proposal and/or resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal and subject to the direction of the OEB. In such case, only the settlement information that is necessary for the purpose of implementing and interpreting the settlement proposal shall be filed and such information shall be filed using the appropriate protections afforded under the relevant legislation and OEB instruments. These obligations shall not impede the filing of this Settlement Proposal itself or its use as evidence in subsequent proceedings including, without limitation, the EB-2017-0049 proceeding.

Further, the Parties have a positive and ongoing obligation not to disclose settlement information to persons who were not involved in the settlement discussions.

1.3 Parameters of Proposed Settlement

All of the elements of this Settlement Proposal have been settled by the Parties as a package, and none of the provisions of this Settlement Proposal are severable. Numerous compromises were made by Anwaatin and HONI with respect to various matters to arrive at this Settlement Proposal. The distinct issues and elements addressed in this Settlement Proposal are inextricably interrelated, and changes in the agreed parameters are likely to have consequences in other areas of this Settlement Proposal, which may be unacceptable to one or more of the Parties. If the OEB does not accept this package in its entirety, then there is no settlement (unless HONI and Anwaatin agree in writing that any portion of the package that the OEB does accept may continue as part of a valid Settlement Proposal).

If the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but neither Anwaatin nor HONI will be obligated to accept any proposed revision. The Parties agree that Anwaatin and HONI must agree with any revised Settlement Proposal prior to its re-filing with the OEB.

None of the Parties can withdraw from this Settlement Proposal except in accordance with the terms contemplated herein (including satisfaction of the Conditions Subsequent) and with Rule 30.05 of the OEB's Rules of Practice and Procedure.

1.4 Full Settlement of Parties

a) HONI will undertake a pilot project that is intended to explore the feasibility of implementing non-wires distributed energy projects (**"Pilot Project")** in and around the Anwaatin First Nations communities as a means to improve reliability in remote and radial areas of HONI's system. The Pilot Project is intended to provide HONI with an opportunity to assess whether similar and repeatable approaches may be used in other remote areas of its system that are experiencing poor reliability conditions.

b) HONI's investment in the Pilot Project shall not exceed $5 million and shall be funded from HONI's distribution capital investment plan.

c) Anwaaatin and HONI agree to work together in an effort to offset or augment this investment amount by obtaining government funding through subsidies or grant programs.

d) The Parties acknowledge that any further funding of this initiative is dependent on (i) the feasibility of the Pilot Project and (ii) further review and approval by the OEB to increase HONI's approved capital investment envelope and recovery through rates of the additional funding requirements.

e) Anwaatin/Anwaatin First Nations communities and Abundant plan to jointly develop and implement up to 45 MW of FIT contracted solar generation in the following repurposed locations:

   a. Longlac M2/Nakina DS: maximum size 5 MW
   b. Moosonee: maximum size 10 MW
   c. Longlac M1/Longlac East DS: maximum size 9 MW
   d. Longlac TS LV bus: maximum size 10 MW
   e. Beardmore DS: maximum size 1.1 MW
   f. Jellicoe DS: maximum size 0.9 MW
   g. Red Rock: maximum size 9 MW.

f) HONI will consider the technical feasibility of having Abundant/Anwaatin First Nation solar generation be used as a source of supply to the energy storage facilities as part of the Pilot Project.
g) HONI commits to processing all connection impact assessment applications made by Anwaatin/Anwaatin First Nations and Abundant in a timely manner, taking into account all other existing connection impact assessment applications HONI has received.
h) The first phase of the Project will complete the technical assessment of energy storage facilities that may improve reliability in the communities served by HONI's F2 Feeder that serves the Nakina area. Energy storage facilities for Phase 1 are targeted to be in-service by March 31, 2019.
i) The design, size and load to be served by Phase 1 facilities are matters not yet determined and will be dependent upon further technical review. HONI will continue to regularly consult with Anwaatin regarding the status of the Phase 1 design.
j) A technical review of Phase 1 implementation is targeted for completion within six months of in-service timing. This information is intended to be used to inform the approaches, design, and viability of Phase 2.
k) During the EB-2017-0049 proceeding, Anwaatin and HONI will provide the OEB with an update on the Project, including any preliminary information regarding sizing of energy storage, siting alternatives and preliminary cost estimates. As part of this update, Anwaatin and HONI may file this Settlement Proposal.
l) The Project shall have no retrospective financial or cost consequences that will require revisiting the amounts assessed and determined by the Board in the EB-2016-0160 Decision.
m) Anwaatin and HONI will consult and cooperate on any other longer-term wires and/or non-wires electricity reliability proposals and solutions affecting the Anwaatin First Nations communities and may jointly pursue other projects intended to improve reliability in other regions served by HONI.

1.5 Description of Project

(a) **Phase 1** is focussed on improving reliability to the communities served by HONI's F2 Feeder situated in the Nakina region. The objective is to provide measurable improvement to the reliability of supply to these communities and as compared to the five-year historical average SAIDI and SAIFI values applicable to these communities. Anwaatin/Anwaatin First Nations, Abundant and HONI intend to achieve this objective through designing and implementing energy storage facilities in close proximity to the referenced communities and the option of having solar generation used to recharge the storage facilities in times of outages.

Anwaatin/Anwaatin First Nations, Abundant and HONI will take reasonable steps to find suitable off-reserve locations in proximity to HONI's feeder distribution facilities to site both solar generation and energy storage facilities at locations in close proximity to local community distribution load.

All constructed Phase 1 energy storage facilities will initially be owned and operated by HONI. HONI agrees to explore in good faith the possibility of Anwaatin First Nations obtaining a minority, non-operating ownership interest in the Phase 1 facilities, should the said facilities proceed to development. The valuation of this interest will be based on HONI's actual investment cost incurred to the date that such interest is acquired by Anwaatin First Nations.

HONI's design of the Phase 1 energy storage facilities will take into account, among other technical factors, historic load levels in the Aroland community. Anwaatin agrees to work with HONI in assessing ways to prioritize distribution service during times of an outage so that stored energy may be used for essential services in the communities.

HONI will consult with Anwaatin/Anwaatin First Nations and Abundant regarding design and sizing of the energy storage facilities.

Anwaatin/Anwaatin First Nations and Abundant intend to jointly develop and implement solar generation facilities in close proximity to all identified energy storage facilities so that the solar generation facilities may be used to supply the energy storage facilities at times when outages occur in the Aroland community.

The targeted timelines for Phase 1 are as follows:

- Scope of work completed and storage partner selected by July 15, 2018
- Siting locations determined and community engagement completed by July 31, 2018
- Completion of all detailed engineering and financial viability review completed by September 30, 2018
- Civil work completed by November 30, 2018

- In-service of energy storage facilities by March 31, 2019.

Anwaatin/Anwaatin First Nations and Abundant acknowledge that targeted timelines may require adjustments, given acquisition timing of requisite land rights, remoteness of worksite locations, workforce availability and the season in which construction work occurs.

(b) **Phase 2:** is focussed on Waaskiinaysay Ziibi Inc. (an economic development corporation representing Rocky Bay First Nation, Bingwi Neyaashi Anishinaabek, Red Rock Indian Band, Whitesand First Nation, and Animbiigoo Zaagiigan Anishinaabek and other smaller First Nations along HONI's A4L transmission line) (collectively, **"WZI"**).

The Phase 2 objective is complete technical assessments of potential non-wires solutions for WZI communities in order to determine whether cost-effective and technically feasible ways may be used through the use of non-wires solutions to improve reliability to levels consistent with HONI's current average SAIDI and SAIFI metrics for its northern rural distribution customers and by deploying similar approaches and measures described in Phase 1. The results of Phase 1 are intended to inform and be used in the technical assessments contemplated for Phase 2.

In Phase 2, HONI and Anwaatin will also work together to identify and evaluate critical loads in MoCreebec Eeyoud locations served by HONI's F1 and F3 feeders and assess whether cost effective and technically feasible non wire energy storage facilities could be implemented to significantly improve reliability for identified critical loads.

Anwaatin will facilitate meetings between HONI, Abundant, WZI and other smaller interested First Nations served by the A4L line in order to describe, explain, and assess solar/storage reliability solutions.

HONI's Phase 2 commitments are limited to preparing technical assessments that consider deployment of energy storage facilities in the WZI communities in the same manner as carried out for Phase 1 and which technical assessments have been filed as part of Exhibit I-6-1(c) in OEB Hearing EB-2017-0049.

Once the technical assessments for Phase 2 are completed, HONI and Anwaatin/Anwaatin First Nations, Abundant and WZI will meet and discuss all technical, operational and financial viability issues that would need to be addressed before any further steps are taken to initiate potential investments. This discussion is intended to explore possible joint development opportunities to implement energy storage and solar generation facilities so that they may be used in an effective and feasible way to provide a means of back-up supply in times of outages for small communities along the A4L route, while maintaining feeder integrity.

(c) **Final Decisions to Proceed with Phase 1 Investments.** HONI's decision to proceed with the work execution and installation of Phase 1 is subject to: (1) investment requirements to not exceed the amounts or outcomes described in paragraph 1.4(b)-(d) above, (2) HONI's technical review and its acceptability to HONI of the final design of the facilities, (3) the level of reliability improvement expected from Phase 1 is reasonably achievable as determined by HONI, and (4) Phase 1 facilities are expected to provide a repeatable outcome for development in other areas of HONI's system. HONI will consult with Anwaatin on the ongoing status of these conditions throughout Phase 1.

1.6 Other Matters

(a) **Ongoing HONI Communications with the Anwaatin First Nations Communities.** HONI and Anwaatin agree to develop and implement a communications plan to facilitate regular communications between them and the First Nations communities to discuss and assess the progress and success of the Pilot Project.

(b) **Pilot for Future HONI/Indigenous Community Cooperation.** If the Pilot Project is successful, HONI and Anwaatin agree to work together and promote the Pilot Project as a potential reliabilty solution in other Indigenous and similarily situated communities.

(c) **Conditions Precedent.** The final form of the Settlement Proposal is subject to the approval of the Band Councils and/or the applicable First Nation governing body(ies).

(d) **Conditions Subsequent.** This Settlement Proposal is subject to the Conditions Subsequent listed in Part A (Preamble) above.

ACCEPTED AND AGREED TO THIS 15 DAY OF JUNE 2018

Ferio Pugliese, Executive Vice President
Customer Care and Corporate Relations
Hydro One Networks Inc.

Larry Sault, President and Chief Executive Office
Anwaatin Inc.

TAB 6

Building Owners and Managers Association Toronto Interrogatory # 31

Issue:

Issue 35: Is the proposed capital structure appropriate?

Issue 16: Are the proposed Z-factors and Off-Ramps appropriate?

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

A-03-01-01 Distribution Business Plan
"Three Competing But Equally Important Factors… responsible stewardship of the distribution system…"

Interrogatory:

a) What legislature mandate does the Company have OSC regulated, OBCA?

b) p5 – Please confirm that Hydro One's goal is to achieve the ROE allowed by the OEB, but not to exceed it. Please discuss.

c) p8 – Given the results of the customer engagement summarized here, please provide an analysis of why Plan C was not chosen.

d) Please provide reference in the IPSOS Report Appendices to support the assertion made in the third bullet on p8.

e) p9 – Please identify the cost savings that will result from each productivity initiative.

f) To what extent will the power quality program (an audit of 200,000 OM&A per year) meet the current large distribution customer demand for the service?

Response:

a) HONI is an OBCA company. Its direct and indirect parent companies (HOI and HOL) are public companies which must comply with the *Securities Act* and are regulated by the OSC. (Please see Exhibit I-3-CCC-9 for the corporate organizational chart.)

b) Hydro One will strive to achieve the ROE allowed by the OEB. Hydro One will share earnings with ratepayers through the ESM mechanism proposed in the Application.

c) Please refer to Attachment 2 of Exhibit I-3-SEC-4. Management concluded that Plan C was not a viable option due to material and reliability system impacts. Key shortcomings to Plan C are:
   i. Replacement levels resulting in an unprecedented service life for poles;
   ii. An increasing number of stations in poor condition; and
   iii. Unacceptable reliability for specific Hydro One customers.

   From Hydro One's perspective, Plan C maintains an asset base that poses unacceptable risks to reliability and safety, which will necessitate significantly higher investment levels beyond the term of this Application that are challenging to resource for Hydro One and challenging to fund for ratepayers. Relative to other utilities, Hydro One's reliability performance is poor. Plan C does the least to improve it, constraining Hydro One's ability to meaningful improve service for all its customers.

   Unprecedented service life for poles
   Plan C replaces poles at a rate that results in an unjustifiably long service life. As Navigant concludes in its pole benchmarking study (Attachment 1 to section 1.6 of the DSP, Exhibit B1-1-1), Hydro One's wood pole inventory is the oldest (37 years), averaging eight years older than the other sampled utilities, which matches the planned life of poles which is ten years older for Hydro One (62 years). As Figure 1 demonstrates, Plan C lowers the pole replacement rate to a level which assumes a planned life for poles of approximately 107 years. This is an unprecedented and unjustified assumed service life for these assets. For comparison purposes, Figure 1 also shows the expected impact of Plan B modified. Pole investments contribute to reliability outcomes, and they are essential for public safety.

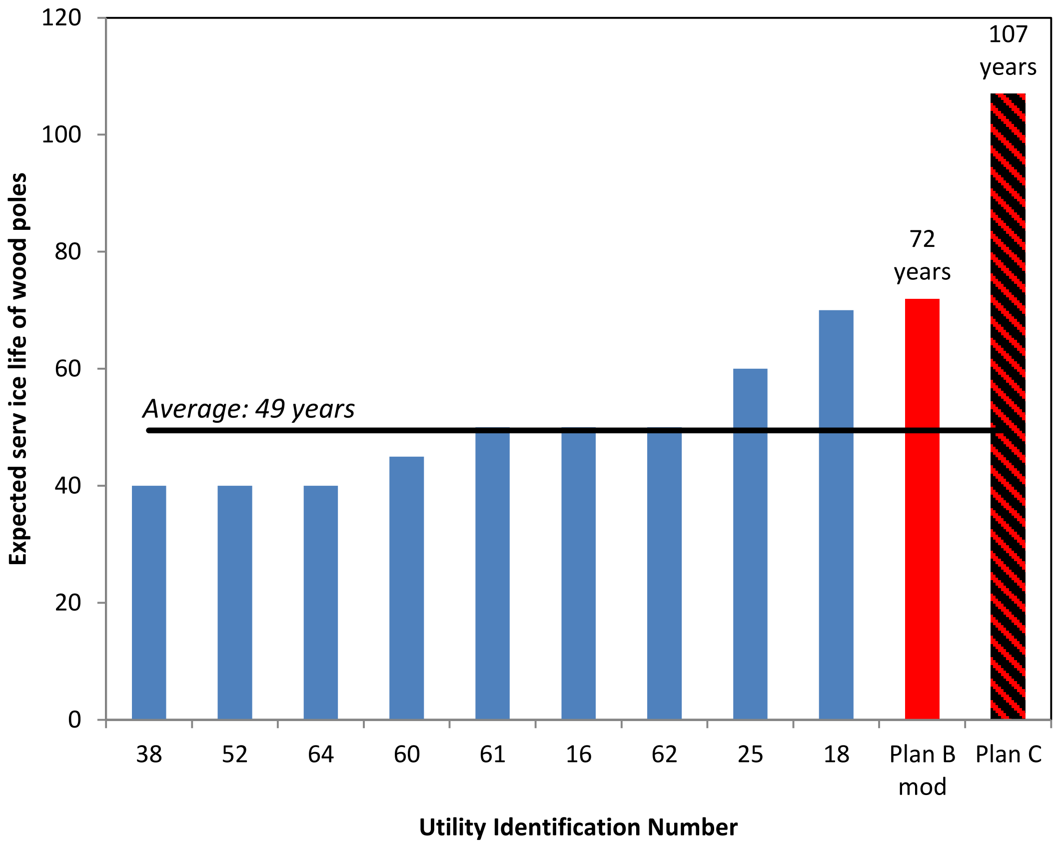

Figure 1: Average Profile of Wood Poles (Navigant)[1]

Stations in poor condition

As compared to Plans A, B, or B-modified, Plan C limits the number of stations refurbishments that are planned for the rate term. Figure 2 shows the expected number of stations in poor condition based on the replacement rates put forward in each of the four plan alternatives. Plan C is the only plan which increases the number of stations in poor condition by 2022.

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[1] Figure 1 presents the information from Figure 14 of the Navigant Study in bar chart format.

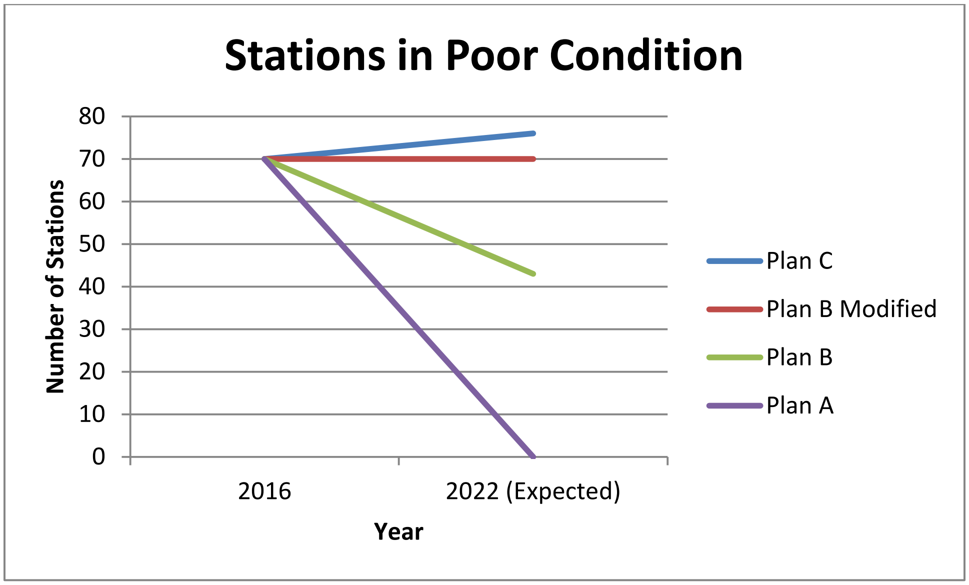

Figure 2: Impacts of Plan Alternatives on Distribution Station Population

Unacceptable reliability for specific Hydro One customers

Plan C would result in unacceptable reliability for specific customers. Figure 3 shows a breakdown of the number of customers that experienced a total of 15 or more hours of interruptions 2017. Figure 4 shows a breakdown of the number of customers that experienced a total of 5 or more interruptions in 2017.

Figure 3 shows, approximately 87,000 customers were interrupted for over 50 hours in 2017. Figure 4 shows, approximately 44,000 customers were interrupted 15 times or more in 2017. Through the Worst Performing Feeder program (ISD SS-06) and associated investments, Hydro One plans to significantly improve reliability for customers supplied by poorly performing feeders. Plan C significantly curtails these activities, meaning unacceptable reliability levels will persist for many of these customers.

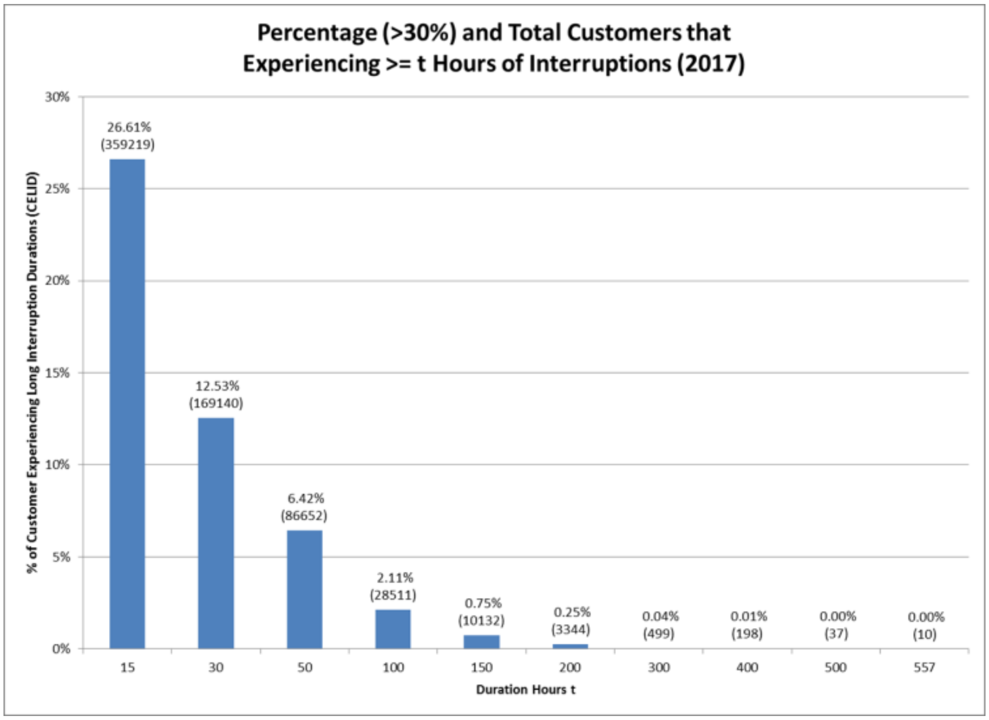

Figure 3: Breakdown of Customers Experiencing Long Interruptions (over 15 hours cumulatively) in 2017

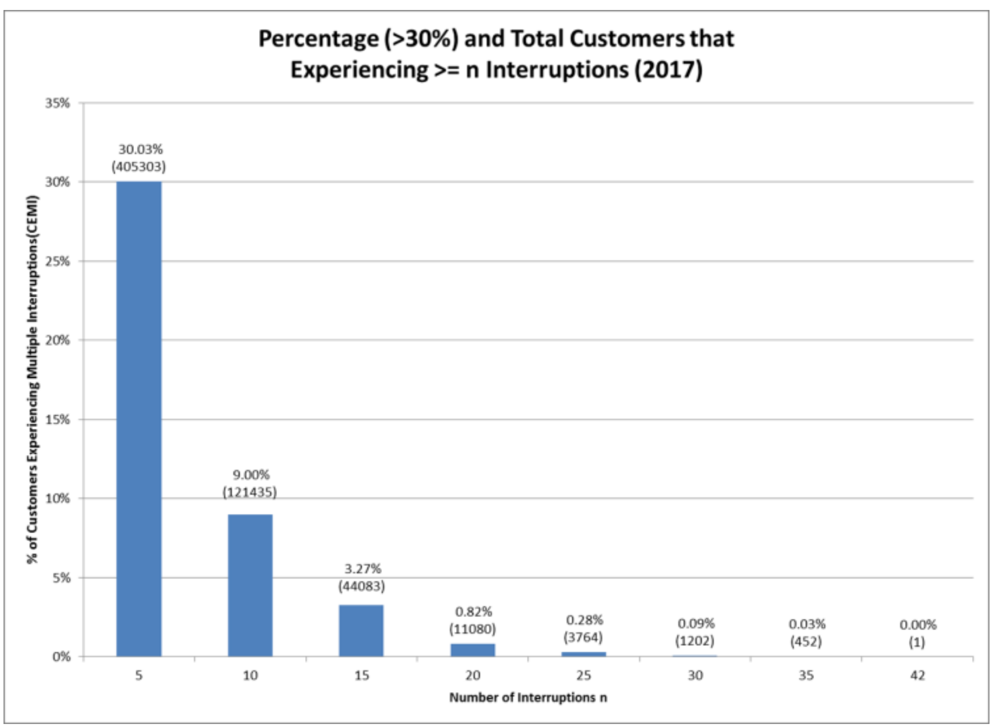

Figure 4: Breakdown of Customers Experiencing Multiple Interruptions in 2017

Witness: LOPEZ Chris and BRADLEY Darlene

Plan B-modified allows Hydro One to improve reliability for these customers as well as Hydro One's overall system reliability metrics considerably. Plan C does not.

Figure 5 compares Hydro One's current reliability to other utilities (2015 non-major event reliability). As Figure 5 highlights, Hydro One's reliability performance is significantly worse, and Plan C would do the least to address it.

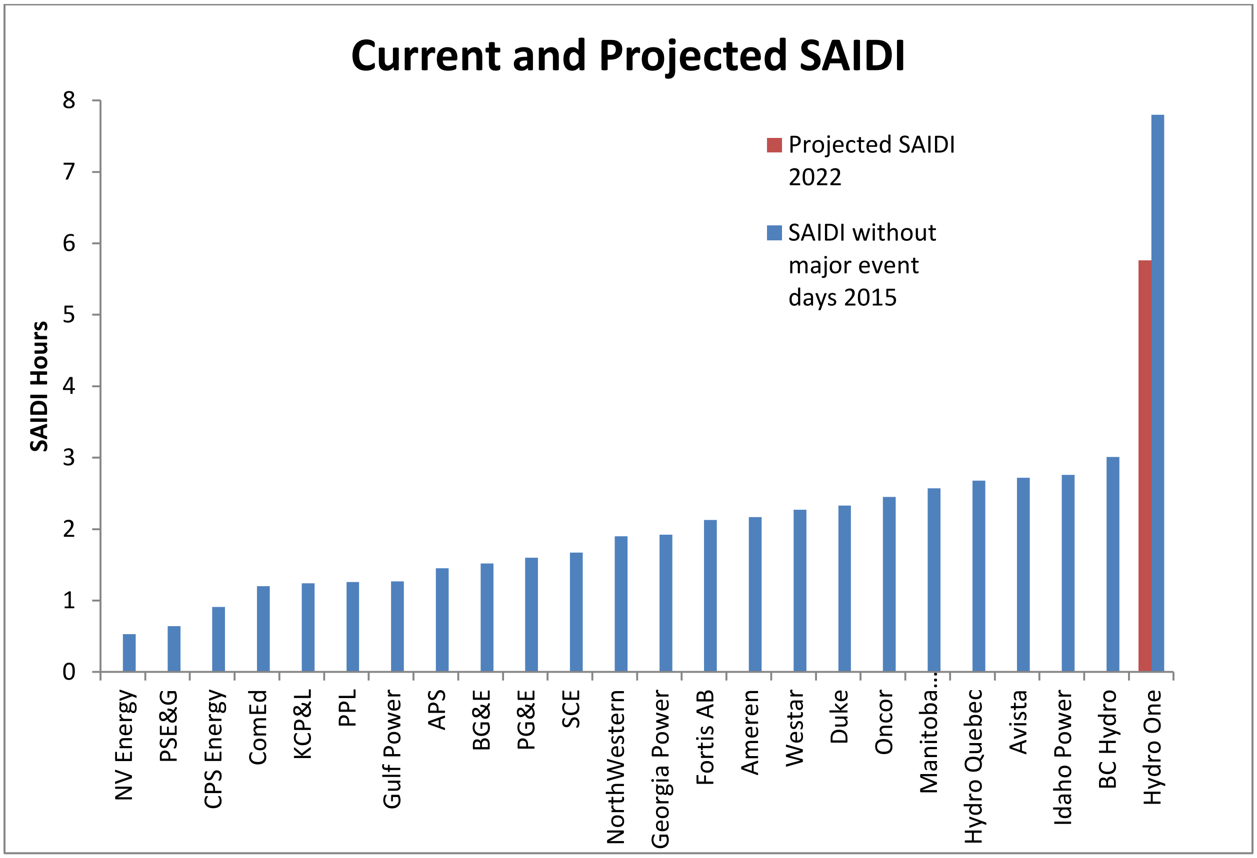

Figure 5: Hydro One's Reliability Relative to Other Utilities and Projected SAIDI

For the reasons explained, Hydro One does not support Plan C. It would lead to a substantial deterioration of asset condition within the short term, and an unacceptable degradation of safety and reliability beyond the term of this Application. Based on an expected increase in failure rates, sustained funding at Plan C levels will eventually lead to significantly higher investment levels that Hydro One will be challenged to resource and are counterproductive to any objective of smoothing rates through prudent investment pacing.

d) Please refer to pages 10 and 121 of the referenced Exhibit.

e) Please refer to Exhibit I-25-Staff-123 response a) for productivity savings that have been embedded in the Dx Business Plan.

f) This program has been budgeted to complete one audit per year. It is expected that this will meet large customer demand for this service. However, the program will be monitored to determine how demand develops overtime.

Witness: LOPEZ Chris and BRADLEY Darlene

TAB 7

Written Statement – I-24-Anwaatin-008

Preamble
During the March 5, 2018 Technical Conference session, and in the context of I-24-Anwaatin-008, Hydro One committed to taking under advisement, but not as an undertaking, to review and determine if ten years of reliability data is available and what issues there may be with providing the data.

Response
Hydro One has raw data for the previous ten years, but in the responses to I-24-Anwaatin-008 provided information for the five-year period spanning 2012 to 2016.

Although, raw data spanning ten years exists, Hydro One maintains that there are two principal issues with providing this data in the context of an application where it may be relied upon to produce arguments or render decisions.

Of primary concern, is that the transmission system (i.e. the configuration of supply) has experienced significant changes in its configuration over ten years. The changes in the configuration of supply inherently impacted the reliability of the distribution system over time. Although changes in the configuration of supply are expected and the supply system is not static, examining reliability trends or contemplating distribution reliability performance over an extended period of time, such as ten years, introduces greater variability due to the configuration of supply, rendering a meaningful analysis impractical, and likely, inaccurate. While a five-year window is still subject to changes in the configuration of supply, it represents a much smaller and recent period in time which is more relevant for trending and for comparisons.

Additionally, the consistency for collecting and reporting data, i.e. the methodology used, over ten years cannot be verified.

For these reasons, Hydro One maintains that providing ten years of distribution system data is not appropriate and that such data cannot be used to infer any meaningful information or be used for correct trending and analysis. If compelled to provide this information, the Company cautions that the information should not be used to produce arguments for or against or to be used in rendering a decision in its current or future applications before the Ontario Energy Board.

TAB 8

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2016-0160**	**Hydro One Networks Inc. Transmission**
VOLUME:	**4**	
DATE:	**November 29, 2016**	
BEFORE:	**Ken Quesnelle**	**Presiding Member**
	Emad Elsayed	**Member**
	Peter C.P. Thompson, Q.C.	**Member**

MS. GUIRY: Read it?
MS. DeMARCO: Yes, please.
MS. GUIRY: "You're asking about risk, not performance. For me, as an end user, risk is your problem. My problem is performance. At the end of the day, do I have it or not. I am worried about how many outage hours I have, not how many I potentially have."
MS. DeMARCO: And this is a verbatim comment?
MS. GUIRY: It is.
MS. DeMARCO: Thank you. Last, as I understood your comments, Mr. McLachlan, is that five years is good data, ten years is better data. And that explained the difference between some of the charts we saw in the presentation and some of the figures we saw in the evidence; is that fair?
MR. McLACHLAN: I don't agree with what you just said in paraphrasing. I think you said five years is good data, ten years is better data. Was that what you just said?
MS. DeMARCO: Let me walk you through it step by step. As I understood your evidence, you did not agree that reliability was improving over a ten-year trend. You did agree that it was improving over a five-year trend; is that right?
MR. NETTLETON: Mr. Chairman, maybe we could have the witness refer to the evidence where that -- and I think it's in his presentation deck that he –
MS. DeMARCO: I am happy to. It's at my tab 2. It's

in the presentation done by Hydro One, and it is on slide -- starting at slide 9 of that, and going on to slide 10 of that. Here you've got ten years of data, yes?

MR. McLACHLAN: Correct.

MS. DeMARCO: And your scorecard, which is in the evidence at -- I will get you the exact reference, had five years of data, is that fair?

MR. McLACHLAN: Yes. The five years of data that would appear in this graph right here on the screen on the left.

MS. DeMARCO: Yes. And so, while others questioned you about reliability performance increasing, getting better, you indicated that it's relatively flat.

MR. McLACHLAN: Yes, there is a slight -- what I think I said is that there is a slight improvement in 2014 and '15. So you could say that reliability has improved in the years 2014 and '15, from this graph that shows that in comparison to 2013, '12 and '11.

My comment about reliability is that it -- reliability is not something that you should be looking at over a short-term time frame because of the volatility of the underlying factors, in particular for Ontario because of the volatile weather. So you should be looking over a longer-term time frame.

MS. DeMARCO: Perfect. Can I ask you to turn to Exhibit I, tab 10, schedule 3, at page 5? Exhibit I, tab 10, schedule 3, at page 5, (iv).

So you've indicated we should look at reliability over a longer term and we have a ten-year duration here. This is the reliability for my clients. How is it doing over that ten-year period?

MR. McLACHLAN: I need a moment to take a look at this. Can you go up, so I can see the context of what this is?

All right. So if I recall for this interrogatory, there is two sets of data here, I believe. There is First Nations data and then there is also Hydro One service territory. It's quite a bit of data to have to take a look at in one moment --

MS. DeMARCO: I am just asking you the lack at number 4, the SAIDI figure --

MR. McLACHLAN: All right, please put it back up on the screen, what Ms. DeMarco has asked for.

MS. DeMARCO: -- for First Nations communities, my clients.

MR. McLACHLAN: Yes.

MS. DeMARCO: So that SAIDI data over the ten-year period, would you agree with me that in 2006 we went from a T-SAIDI of 85.4, to 2015 we went to T-SAIDI of 522.8.

MR. McLACHLAN: Yes, that's what the data shows.

MS. DeMARCO: And subject to check, would you agree with me that that is several multiples? I am working on my math here, it's a good seven times more. So the SAIDI, T-SAIDI increased more than seven times over the period of that ten years?

MR. McLACHLAN: Are you referring from the 2006 value to the 2015 value?

MS. DeMARCO: That's right.

MR. McLACHLAN: So I guess my comment, without doing a more detailed analysis on this, is that this is a very dangerous thing to do, to pick endpoints of reliability because just as easily, one could pick 2010 to 2015 and say that reliability has improved 30 percent.

I am not meaning to be smug, Ms. DeMarco. But the fact is when you look at reliability performance, you have to look at it over a period of time and in a rolling average.

So I respect that in 2006, the duration of interruption was very low, and that in 2015, it's much higher. Without having the underlying analysis of what this is and what the causes are, just looking straight at the numbers, yes, I would say that the last three years are a significant increase compared to the three years before.

MS. DeMARCO: Would you undertake to provide that rolling analysis for this ten-year period? Because we do have ten years of data here.

MR. McLACHLAN: I think the better question is to focus on whether there needs to be a further investigation into the actual delivery point and source supplies for these delivery points that feed this sub indices here.

MS. DeMARCO: So I will take that as a no, you will not undertake to provide that data that you said would be more relevant?

MR. McLACHLAN: What data is it that you are asking for? What I am saying is that when you pick endpoints, when you pick two spot points and do a comparison, it's different than to take an average over a longer time frame.

MS. DeMARCO: So would you undertake to take that average over a longer time frame?

MR. McLACHLAN: We can provide that, the question is you can also calculate it by taking the '11 to '15 average yourself right there.

MS. DeMARCO: Over the 2006 to '15. But in terms of the change, would you agree with me it's not getting better?

MR. McLACHLAN: I would agree that the performance looks like it is not improving.

MS. DeMARCO: And same for the delivery point on reliability index? It's not getting better over that ten-year period of time?

MR. McLACHLAN: Based on the numbers that are there; that's correct.

MS. DeMARCO: Thank you, those are my questions.

MR. QUESNELLE: Thank you, Ms. DeMarco. Let me just do a time check here. Ms. Grice, the original estimate of 15 minutes, are you still on track for that?

MS. GRICE: I might be closer to 20 minutes.

MR. QUESNELLE: Okay, thank you, and Ms. Lea?

MS. LEA: It kind of keeps changing with what I am hearing. I am estimating 20 minutes at this time.

MR. QUESNELLE: Okay. Why don't we take our break at this juncture then, and we will return at 3:35.