TABLE OF CONTENTS

TABLES

ATTACHMENTS:

EXHIBIT 1 - ADMINISTRATIVE INTERROGATORIES

OEB STAFF

1-Staff-1

Updated Revenue Requirement Work Form (RRWF) and Models

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet and may also be included on other sheets in the RRWF to assist understanding of changes.

In addition, please file an updated set of models that reflects the interrogatory responses. Please ensure the models used are the latest available models on the OEB's 2024 Electricity Distributor Rate Applications webpage.

SNC response:

The following models have been updated and are filed with interrogatory responses:

- Revenue Requirement Workform ("RRWF")
- Filing Requirements Chapter 2 Appendices
- Cost Allocation Model
- Load Forecast Model
- DVA Continuity Schedules
- RTSR Workform
- Tariff Schedule & Bill Impact Models
- PILS Model

The following table outlines the list of major updates that were completed to the models as a result of the responses to these IR's.

TABLE 1-1 SUMMARY OF COS MODEL UPDATES

IR Response	Description of Update	Models Updated
OEB Error Checking:	A principal adjustment of ($6,669) was added to the 2024 GA Analysis workform, Principal Adjustments Tab for the Kenora Rate Zone.	TB_2024_GA_Analysis_Workform_Updated_20230921 KN_2024_GA_Analysis_Workform_Updated_20230921
4-SEC-19, 6-SEC-27	Please provide a revised version of Appendix 2-JC that includes additional columns to show year-to-date actuals for 2023, and year-to-date actuals at the same point in time in 2021 and 2022	Revised Chapter 2 Appendices, Tab 2-JC
4-CCC-17	Please provide an updated version of Appendix 2-JA which includes 2023 year to date actuals	Revised Chapter 2 Appendices, Tab 2-JA
4-VECC-37	Please update the 2023 bridge year in Appendix -JC and include actual spending to date and the current estimate for the remaining year-end spending	Revised Chapter 2 Appendices, Tab 2-JC
2-SECC-15, 2-STAFF 9	Year to Date 2023 Actual Capital Expenditures to be updated in 2-AA and 2-AB	Revised Chapter 2 Appendices, Tab 2-AA, Tab 2-AB
2-VECC-7	Please update Appendix 2-AA to show 2023 actuals and in a separate column the current forecasted year-end expenditures for 2023	Revised Chapter 2 Appendices, Tab 2-AA
3-VECC-24 3-VECC-34 3-VECC-36	Load forecast revisions. The load forecast revisions are carried forward to the cost of power calculations, the Cost Allocation Model (including I8 Demand Data), the RRWF, and the DVA models	Revised Ch 2. Appendices, Tabs 2-IB, 2-ZA and 2-ZB SNC_2024_Cost_Allocation_Model_20231110 KN_2024_Continuity_Schedule_CoS_20231110 SNC_2024_DVA_Continuity_Schedule_CoS_20231110 TB_2024_Continuity_Schedule_CoS_20231110
4-SEC-21	SNC has updated the 2K to adjust the value reported as allocated capital to actual in 2024 test year.	Revised Chapter 2 Appendices, Tab 2k
5-VECC-53	Recalculated the long-term debt rate making the appropriate pro-ration adjustment	Revised chapter 2 Appendices, 2OA
5-VECC-53	Recalculated the long-term debt rate making the appropriate pro-ration adjustment	Revised Chapter 2 Appendices, 2OB
7-STAFF-57	Updated Billing and Collecting Weighting Factors for USL class	Revised Cost Allocation Model: SNC_2024_Cost_Allocation_Model_20231110
8-STAFF-63	Revised RTSR Workform	Revised: SNC_2024_RTSR_Workform_20231110
9-STAFF-66	Update Q4 2023 and Jan - April 2024 interest rate on DVA's.	Revised: KN_2024_Continuity_Schedule_CoS_20231110 SNC_2024_DVA_Continuity_Schedule_CoS_20231110 TB_2024_Continuity_Schedule_CoS_20231110
9-STAFF-67	Revised presentment of Principal Adjustment, reported in Opening balance.	TB_2024_Continuity_Schedule_CoS_20231110
9-STAFF-68	Updated DVA Schedules for revised GR2 Green Button costs.	Revised: SNC_2024_DVA_Continuity_Schedule_CoS_20231110
9-STAFF-70	Updated DVA Schedules for revised GR2 1518 & 1548 2023 Activity.	Revised: KN_2024_Continuity_Schedule_CoS_20231110 TB_2024_Continuity_Schedule_CoS_20231110
Load Forecast, Distribution revenue, Interest and DVA balances	Revised Tariff Schedule and Bill Impact Models.	Revised: KN_2024_Tariff_Schedule_and_Bill_Impact_Model_20231110 TB_2024_Tariff_Schedule_and_Bill_Impact_Model_20231110

IR Response	Description of Update	Models Updated
9-STAFF-68	Removed $44,000 of budgeted Green Button Portal Costs from OM&A expenses.	Revised: Revised Chapter 2 Appendices, Tab 2-JA, 2-JB, 2-JC, 2023 Bridge Year
2-VECC-7	Revised 2023 capital asset additions in the Chapter 2 Appendices, Tab 2-BA based on Revised 2023 Forecast.	Revised: Revised Chapter 2 Appendices, Tab 2-BA 2023 Bridge Year to 2023 Revised Forecast
6-VECC-55	Revised 2024 Test Year Other Revenue UsOA Account 4235 for $94,691, in the Chapter 2 Appendices, Tab 2-H as SNC identified budgeted engineering hours allocated to recoverable work as part of the budgeting process, and the offsetting income for these hours was not recorded.	Revised: Revised Chapter 2 Appendices, Tab 2-H
4-SECC-21	SNC revised the allocation between OM&A and Capital reported on the 2K from the original values of $12,044,462 for OM&A and $5,391,744 for capital to $12,194,449 to OM&A and $5,241,757. Total compensation values did not change, only the allocation between Capital and OM&A.	Revised Chapter 2 Appendices, Tab 2-K

1-Staff-2

Green Button

Ref 1: Exhibit 1, Tab 3, page 46

Preamble:

Distributors are required to implement Green Button by November 1, 2023. The OEB has approved the establishment of a generic deferral account for rate regulated distributors to record the incremental costs directly attributable to the implementation of the Green Button initiative. Synergy North has identified the Green Button implementation in 2023 as putting upward pressure on costs.

Question(s):

a) Please describe Synergy North's progress towards Green Button implementation.
b) Please confirm whether Synergy North has proposed any capital or OM&A costs associated with the implementation of Green Button initiative for the 2023 bridge and 2024 test year.

SNC Response:

a) SNC is conducting Green Button certification testing and anticipates launching within the coming weeks.
b) Green Button required SNC to convert to a new portal. SNC's former provider could not commit to ongoing development for the required Green Button implementation. The new portal came with significantly increased expenses. Yearly maintenance went from $8,900 in 2021 to $35,000 for the annual fee from June 2022 to the end of May 2023.

Green Button costs to date:

- SEW Year 1 (2022) Green Button development and supporting customer portal $20,417.
- SEW Year 2 (2023) Green Button development and supporting customer portal $35,583.
- Green Button Alliance certification services $3,700 USD
- Green Button Alliance pre-certification testing services $1,000 USD

Green Button costs to date, as detailed above, total $62,439, which have been included in Account 1508 – Green Button Deferral for 2023. Please refer to the response to 9-Staff-68.

See Exhibit 4, Table 4-6, OM&A Expenditures 2017 BA Proxy to 2024 Test Year. $49,000 is included as the 2023 Bridge Year, and $76,000 expenses for Green Button annual costs are included in the 2024 Test Year OM&A.

1-Staff-3

Net-Zero Carbon Goals

Ref 1: Exhibit 1, page 94

Preamble:

In reference 1, Synergy North states that it has partnered with the City of Thunder Bay, Lakehead University and BlueWaveAI to develop an artificial intelligence (AI) data-driven simulation platform for the City of Thunder Bay to accelerate the adoption of an electric transit system that supports the city's road map towards meeting the local net-zero (NTZ) carbon goals.

Questions(s):

a) When does Synergy North expect this study to conclude and how has it used any preliminary analysis (if available) for prioritizing future projects and in developing its capital plan?
b) What other steps is Synergy North taking to prepare for the increased electrification in order to meet the NTZ carbon goals?
c) How has Synergy North planned for vehicle electrification, given that Canada's Emissions Reduction Plan mandates that all new light-duty vehicle sales will be net-zero emission vehicles by 2035? What challenges will the uptake of EVs bring to Synergy North during the DSP period?

Has Synergy North considered the use of Level 1 versus Level 2 EV chargers and the difference in load associated with each?

d) Through the federal Greener Home Initiative, residents are being encouraged to switch to cold climate heat pumps for space heating. Has Synergy North considered the uptake of cold climate heat pumps over the coming years? What challenges has this brought to Synergy North, and how has it affected planning during the DSP period?

SNC Response:

a) SNC expects that this study will conclude by the end of 2023, and no preliminary analysis has been released to SNC.

b) SNC has been preparing for increased electrification in the following manner.

- Participation in the EDA's Electrification Council and sharing information with other utilities.
- Working closely with the City of Thunder Bay on its Transit Electrification Plan.
- Engaging large customers with respect to their Net Zero Plans – See DSP Page 17.
- Obtaining MTO registered EV data set and geospatially locating using the GIS system.
- Implementing a quarterly process to review the loading of transformers using individual meter data.
- Obtaining voluntary registration information from customers for EVs.
- Consulting with Power Advisory on a DER future.
- Consulting with IESO on load forecasting – See DSP Page 49.

c) SNC has planned for vehicle electrification through the initiatives listed above, as well as through the IRRP process to incorporate EVs into its load growth data. SNC does not expect to experience challenges due to the uptake of EVs during the DSP period, as stated on Page 8 of the DSP. SNC has considered the load associated with both types of chargers and how that may impact a typical residential customer connection.

d) SNC did not consider the uptake of cold climate heat pumps in its forecast during the DSP period.

1-STAFF-4

Net OM&A Savings

Ref 1: Exhibit 1, page 94

Preamble:

In Table 1-35: Summary of Operating Synergies, Synergy North states that 2022 forecast synergies were $848k and 2023 forecast synergies were $884k.

Question(s):

a) Please provide actual synergies achieved for 2022 and 2023 to date, as available.
b) Can Synergy North confirm that the actual net OM&A savings have exceeded the forecast net savings of $2.47M indicated in the MAADs proceeding3?
c) Please map the OM&A reductions shown in Table 1-35 in reference 1 to the OM&A programs in Appendix 2-JC that they are recorded in.
d) Please provide estimates of continued synergies expected in the forecast period?

SNC Response:

a) The title of the 2022 balance, as listed in Table 1-35, should have read “2022 Actuals”, not “2022 Forecast”, these values represent the actual synergy savings in 2022. SNC has not adjusted its post-merger plans, and as such, with the exception of the PLT and Customer Service wages, all other items are known savings and can be pro-rated with 10/12th's being achieved by the end of October 2023. As at October 13th, 2023, the YTD PLT savings is $104,372. The YTD customer service savings is $49,428.
b) SNC confirms that total OM&A savings will exceed the $2.47M indicated in the MAAD proceeding at the end of 2023.

c) Please see Table 1-2 below for the OM&A savings mapped to Appendix 2-JC Programs.

TABLE 1-2: OM&A SAVINGS MAPPED TO APPENDIX 2JC PROGRAMS

Summary of Cumulative Annual Operating Synergies	**OM&A Program - 2JC**
PLT Reduction	67%- Overhead/ Undergound Maintenance 16% - Overhead/ Underground Operations 1% -Station Maintenance 16% - Tree Trimming
Executive Management wages and benefits	President and Board of Directors
Property Insurance	General Administration
Commercial Liability Insurance	Insurance
Kenora City Allocation	18% - General Administration 82%- Billing and Collecting
Customer Service Clerk	Customer Billing
Billing and computer services	Customer Billing
EDA membership fee reduction	General Administration
Audit fees	Corporate Expenses
USF Membership fees	Finance, Regulatory and Purchasing
Radio Licence reduction	General Administration
Board Fees	President and Board of Directors
Software Redundancy	General Administration
Operational changes in Kenora	General Administration

d) Please see Table 1-3 below for estimates of continued synergies expected.

TABLE 1-3: ESTIMATED FORECASTED MERGER SYNERGIES (2024-2028)

	2024	**2025**	**2026**	**2027**	**2028**
PLT Reduction	160,928	164,147	167,430	170,778	174,194
Excutive Management Wages and Benefits	185,719	185,719	185,719	185,719	185,719
Property Insurance	20,000	20,000	20,000	20,000	20,000
Commercial Liaiblity Insurance	15,000	15,000	15,000	15,000	15,000
Kenora City Allocation	242,610	242,610	242,610	242,610	242,610
Customer Service Clerk	60,913	62,131	63,373	64,641	65,934
Billing and computer services	110,432	110,432	110,432	110,432	110,432
EDA mebership fee reduction	19,856	20,253	20,658	21,071	21,492
Audit fees	27,555	27,555	27,555	27,555	27,555
USF Membership fees	8,750	8,750	8,750	8,750	8,750
Radio Licence rduction	611	611	611	611	611
Board Fees	8,160	8,160	8,160	8,160	8,160
Software Redundancy	26,466	26,466	26,466	26,466	26,466
Operation changes in Kenora	7,000	7,000	7,000	7,000	7,000
	$ 893,999	$ 898,833	$ 903,764	$ 908,793	$ 913,923

1-STAFF-5

Letters of Comment

Following publication of the Notice of Application, the OEB received four letters of comment. Section 23.03 of the OEB's Rules of Practice and Procedure states that "Before the record of a proceeding is closed, the applicant in the proceeding must address the issues raised in letters of comment by way of a document filed in the proceeding." If the applicant has not received a copy of the letters or comments, they may be accessed from the public record for this proceeding.

Please file a response to the matters raised in the letters of comment referenced above. Please also ensure that responses to any matters raised in subsequent comments or letter are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

SNC Response:

SNC received four letters of comment:

- R Mancuso: 20230914
- TW Jewell: 20230914
- T Jewell: 20230914
- A Huzan: 20230914

The responses to each of these letters are included as Attachment 1-1: Responses to Letters of Comment, and individually filed directly on the OEB's Regulatory Electronic Submission System (RESS) portal. SNC will continue to monitor the OEB website for Letters of Comments.

1-STAFF-6

Customer Engagement

Ref 1: Exhibit 1, page 67

Ref 2: Exhibit 4, Attachment 4-C, Vegetation Management Plan, page 16

Preamble:

In reference 1, Synergy North states,

"Customers were agreeable to the vegetation management spending. Overall, customers chose an option which suggested SNC spend more on the vegetation management program to ensure it is compliant with CSA standards. The majority of customers chose to spend between $1.00 and $1.50 per bill, as opposed to the other choices contained within the survey."

In reference 2, Synergy North states that all three scenarios of vegetation management spending were presented to the Local Advisory Committee (LAC). The LAC agreed that the cost of $1.50-$2.00 was the best approach.

Question(s):

a) Please provide an estimate of the $ impact per bill of the proposed level of vegetation management in 2024?
b) Please explain how customer preferences have been taken into account when developing the vegetation management plan in reference 2?
c) Please describe any changes made to the proposed capital and operating plans as a result of any feedback received through the customer engagement survey.

SNC Response:

a) The question posed to customers was based on the additional incremental forestry spending. Management's plan, as presented in the application, is an additional $1.35M. This additional spending is $1.26 per customer/month.

b) Customer preference with regards to the vegetation management plan was gathered using two separate surveys attached in Exhibit 1, Attachment 1-K, Phase 1 and Phase 2, Have Your Say survey. The initial survey asked customers to give feedback about whether SNC should be clearing with some forecasted costs of pacing. In the first survey results, customers were clear that they agreed with clearing vegetation. The second survey asked customers directly about the pacing and bill impacts of the vegetation management plan. Customers responded with a majority, preferring a $1.50 bill impact with the related plan. Both surveys were written with the direct input of the Local Advisory Council (LAC). During the development of the surveys, the LAC was presented with the vegetation management plan to ensure they were able to provide informed feedback for the survey questions. The statement in reference 2 above was in relation to the LAC providing feedback on the vegetation management plan.

c) No changes were made to the Vegetation Management Plan as a result of the customer engagement survey, as customer preferences aligned with the pacing and required bill impacts to implement Scenario 2 of the Vegetation Management Plan, which was recommended by management.

1-Staff-7

E-billing

Ref 1: Exhibit 1, page 58

Ref 2: Exhibit 1, Attachment 1-F, SNC Customer Satisfaction Survey, page 17

Preamble:

In reference 1, Synergy North states,

"SNC continues to automate and digitize processes, which has reduced paper, ink, storage, and postage costs through various efforts. SNC offers an E-Billing option to customers, which has proven to be a popular and convenient service for customers. The E-Billing Campaign started in 2020 which included a $5 donation/ rebate if customers move to e-billing. In early 2020, SNC 15,247 customers on e-billing, as of February 2023, 20,383 customers are on e-billing, which represents a 33% increase. Each year SNC's storage requirements are decreasing which will ultimately result in savings to the ratepayer."

In reference 2, Synergy North asked customers about various incentives that would encourage them to switch to e-billing.

Question(s):

a) Has Synergy North undertaken any steps towards moving more customers to e-billing based on the responses in reference 2? If yes, are the cost savings reflected in Synergy North's OM&A?
b) How much does Synergy North expect to save through e-billing in the 2024 test year?

SNC Response:

a) Yes, SNC runs a yearly e-billing campaign encouraging customers to sign up for e-billing. The cost savings are included within the OM&A. Currently, SNC has 33% of customers on e-billing.

b) Refer to answer 1-CCC-9.

1-Staff-8

Activity and Program-based benchmarking

Ref 1: Exhibit 1, 1.6.6, page 87

Ref 2: **APB Unit Cost Calculations: 2021 Results (xlsx) - 27 March 2023**

Preamble:

In reference 2, Synergy North's unit cost for years 2019 to 2021 are as follows:

Distributor	Table 4: Unit Cost Indexes by Distributor: Lines O&M		
	Unit Cost ($/Circuit km of Primary Line)		
	2019	2020	2021
Synergy North Corporation	2,800.23	2,102.20	2,309.18

"Table 1-31: Activity and Program Based Benchmarking – Forecasted Results from 2022 to 2024" in reference 1 provides the 2022 actual and 2023 and 2024 forecast unit costs for Lines O&M program as follows:

Activity	**Measure**	**2022**	**2023 Forecast**	**2024 Forecast**
Lines O&M	$/Circuit km of Line	3,304.91	2,773.03	3,075.66

In reference 1, Synergy North states that removal of skywire commenced in 2022.

Question(s):

a) Approximately what proportion of the unit cost increase from 2021 to 2022 ($ 2,309.18 to $3,304.91) was due to the costs related to skywire removal project?
b) Has the Skywire been eliminated from all the locations that Synergy North deemed as hazardous to workers and to public in 2022? If no, what years is Synergy North planning to eliminate them?
c) Are there any further plans beyond 2022 to remove skywire from the remaining locations that might be currently deemed as non-hazardous?
d) Do 2023 and 2024 forecasted unit cost in the above table include any skywire removal project costs? If no, please explain the reasons for the elevated levels of unit costs as compared to the historical actual unit costs (e.g., 2020 and 2021).

SNC Response:

a) As per Exhibit 4, page 30, line 20, the total Skywire impact in 2022 was $433,733. This equates to $343.96 per circuit KM of primary line.
b) SNC was able to remove all the Skywire from the system in 2022, and the 2023 budget is based on a more normalized spending; adjusted for inflation, see Part (d) below.
c) No further plans beyond 2022 to remove Skywire; it was all removed in 2022.
d) 2020 and 2021 are not appropriate historical values for comparison as a result of the impacts of COVID-19 (please see Exhibit 4, section 4.1.6). As explained in Exhibit 4, as a result of the significant concerns about customers' ability to pay their invoices during 2020, and ultimately, that impact on the utility, Management made certain decisions as listed on page 13 of Exhibit 4. Included in these decisions was the elimination of contractor work and the transfer of PLTs to capital and recoverable work from OM&A activities. Activities cut in 2020 included all proactive work such as cross-arm replacement, Transformer painting, switch painting and overhead inspections. In addition, non-emergent defective equipment replacement was also deferred, including fibreglass arm replacement, installation of animal protection, and Skywire removal. This resulted in a reduction of contractor costs, labour costs and overhead costs in 2020 to unsustainable levels. As discussed, SNC was unable to secure enough contractors in 2021, as the contractors had accepted work on projects outside of SNC when they had been released in 2020 and those projects continued into 2021 making their resources unavailable to SNC. 2019 is

a better indication of the required necessary spending to properly maintain the system and the values in 2023 and 2024 show a return to stability.

SCHOOL ENERGY COALITION

1-SEC-1

[Ex.1]

Please provide copies of all benchmarking studies, reports, and analyses that the Applicant has undertaken or participated in since its last rebasing application, that are not already included in the application.

SNC Response:

SNC has filed all relevant benchmarking studies, reports and analysis undertaken or participated in since it's last rebasing application.

1-SEC-2

[Ex.1]

Does the Applicant have a corporate/balanced scorecard or similar document used by its Board of Directors to monitor and measure its performance? If so, please provide a copy of each annual document since 2017.

SNC Response:

SNC attaches copies of its Corporate Balanced Scorecard for each year from 2017 to 2022 as Attachment 1-2: Corporate Balanced Scorecard. For clarification, the 2017 and 2018 Scorecards provided relate to Thunder Bay Hydro only. In addition, SNC updated its Corporate Balance Scorecard in 2022, resulting in a change in Key Performance Indicators and format.

1-SEC-3

[Ex.1, p.38]

Does the Applicant share executives with any of its affiliates? If so, please provide details.

SNC Response:

SNC shares executives with its affiliates. The President & CEO oversees all three of the affiliate organizations. The Vice President of Finance, Regulatory Affairs and Purchasing oversees the financial activities of the affiliates. The VP of Engineering and Asset Management oversees the Meter Service provider and locates activities for TBHUSI. The VP of Customer Service oversees all back-office activities for TBHUSI.

1-SEC-4

[Ex.1, p.53-61]

Please quantify the listed productivity and efficiency savings. Please provide details regarding all assumptions made in the calculation.

SNC Response:

SNC provides Table 1-4 below in response to this interrogatory. The table has been expanded to incorporate responses to the following interrogatories: 1-SEC-4 and 1-AMPCO-2. SNC has implemented productivity initiatives and improvements to its business processes as identified on pages 54-60 of Exhibit 1. As identified in Table 1-4, the outcomes of these initiatives are cost savings, avoided costs and/or improved outcomes for customers.

SNC does not track quantitative information associated with productivity initiatives at a consolidated level or as part of its ongoing reporting. However, in an effort to quantify the dollar amounts associated with existing and planned productivity initiatives for the purposes of responding to this interrogatory, SNC has estimated these amounts on a best-efforts basis. The dollar amounts provided are not necessarily cost savings resulting in lower overall expenditures; they could be avoided costs which avoid incurring expenditures in the future (e.g., FTE eliminations are avoided costs which have mitigated increases associated with FTE additions required to meet evolving business needs). For persistent savings, amounts have been calculated assuming 2023 costing.

TABLE 1-4: PRODUCTIVITY AND EFFICIENCY SAVINGS

Efficiencies/ Improvements	OM&A or Capital	Effective Date/ Existing or New in 2024	One-time/ Persistent Cost Savings or Avoided Costs	Application Reference	Calculation Assumptions
Merger of TBHEDI and KHEC	OM&A	2019 – existing	Persistent	Ex 1, pg. 102	Total net merger savings to date forecasted to end of 2023 – $2,946,579, Exhibit 1 (Table 1-35 and 1-36). Persistent annual savings - $884,000 (Calculation assumptions provided in response to 1-SEC-7)
4kV Conversion Program – Capital Replacement	Capital	Conversion Program began in 2007	Avoided Cost – Capital Replacement of Substations	Ex 1, pg.54	Quote provided by Rexel/Hitachi and ABB, estimated cost savings of $33.3 million over 5 years. Refer to 2-Staff 13 for details.
4kV Conversion Program – Station OM&A costs	OM&A	Savings began at start of conversion program as stations were decommissioned, full savings to be realized at end of conversion program in 2027/2028	Persistent	Ex 1, pg.54	$28k annually for each station decommissioned, which is an average of the hydro, water, land tax, liability insurance, and contract costs of the existing stations.
4kV Conversion Program – Inventory/ equipment reductions/ Re-use transformer spares for remaining kV	OM&A	Conversion Program began in 2007	Persistent	Ex. 1, pg. 54	Estimated stock reduction of $32k annually until 2027 when 4kV stock is no longer needed
Consolidation of Office Space	OM&A	Consolidation occurred summer of 2023, full savings to be achieved in 2024.	Persistent	Ex.1, pg 58	7,199 sq ft reduction in leased space, resulting in $118,776 in annual savings.
Efficiencies/ Improvements	OM&A or Capital	Effective Date/ Existing or New in 2024	One-time/ Persistent Cost Savings or Avoided Costs	Application Reference	Calculation Assumptions
Fleet Utilization: Purchasing Stock Fleet vs. Custom Builds	Capital	2019 - existing	Persistent	Ex. 1, pg 55	Savings on every double bucket replacement of $60k based on comparison of custom double bucket purchased in 2017 versus a stock double bucket purchased in 2019.
Fleet Utilization: Re-purposing Fleet	Capital	2019 - existing	Avoided Cost	Ex. 1, pg 55	By SNC repurposing/ re-building fleet SNC has avoided the costs of buying the following: Dump Trailer - $20,000 Two new cab and chassis - $200,000 ($100k each)
Survalent Outage Management System		2020 - existing	None	Ex. 1, pg 55	No cost savings, improving the accuracy of recording both customers affected and interruption minutes.
Installation of Reclosers	OM&A	2010 – existing	Persistent	Ex 1, pg 55	Savings related to automated switching and the avoided cost of sending staff / trucks to site to manually operate switch - $19k (Savings of 20 manual operations / call outs with a crew of 2 with a truck)
SNC has inhouse locators to perform meter removals outside of peak periods	OM&A	2021 - existing	Persistent	Ex 1, pg 56	Savings of approximately $5,000 annually
Cross training of staff	OM&A	Ongoing	Avoided Cost	Ex. 1, pg 56	Avoided cost of FTE additions required to meet evolving business needs through cross training employees in multiple areas.
Position Elimination – Cashier Finance	OM&A	2019 – existing	Persistent	Ex 1, pg. 57	One fully burdened FTE in department - $61,225
Position Elimination – Mail Clerk	OM&A	2020 – existing	Persistent	Ex 1, pg. 57	Part Time FTE in department - $9,960
Position Elimination –Billing Clerk	OM&A	2022 – existing	Persistent	Ex 1, pg. 57	One fully burdened FTE in department - $56,807
Position Elimination – Customer Service Clerk	OM&A	2020 – existing	Persistent	Ex 1, pg. 57	One fully burdened FTE in department - $51,353
Position Elimination – Two Station Technicians	OM&A	2020 – existing	Persistent	Ex 1, pg. 57	Two fully burdened FTE in department - $198,380
Position Elimination – Powerline Technician (PLT moved to Supervisory, PLT position not backfilled)	OM&A	2019 – existing	Persistent	Ex 1, pg. 57	One fully burdened FTE in department - $99,190.29
Restructuring Plan – Replacing Operations Manager with a Lines Supervisor in Kenora	OM&A	2019 – existing	Persistent	Ex 1, pg 57	Difference between Operations Manager burdened cost and a Lines Supervisor burdened cost
Automated Phone Call System	OM&A	2019 – existing	Persistent	Ex 1, pg. 57	For emergency work, 2 Hours of System Control Time, and reduced outage time is achieved - $91,285 in savings
E-billing	OM&A	2020 – existing	Persistent	Ex 1, pg 58	Refer to 1-CCC-9
Elmination of mail delivery service between SNC's two locations	OM&A	2022 - existing	Persistent	Ex 1, pg 59	Contract for mail delivery services with Courtesy Freight of $12,000 eliminated.
Internal staff providing training versus external consultants	OM&A	2023 - existing	Persistent	Ex 1, pg 59	Savings of $6,000 to $11,000 annually based on amounts spent in previous years on programs that we can now internally provide training for.
Collective agreement changes - trades staff move to 20 min on the job paid lunch, versus 30 minute unpaid	Capital & OM&A	2021 – existing	Avoided cost	Ex 1, pg 59	Tear down and drive time and re-set up of 1 hour for offsite paid 30 min lunch, versus on-site paid 20 min lunch with 10 minutes of transition time result in savings of 30 minutes of additional on tool time. The cost efficiencies are calculated to be $168,466 based on 1,584 hours of time saved multiplied by a an hourly burdened PLT cost of $106.36.
Re-fueling agreement with the City of Thunder Bay	Capital & OM&A	2019 - existing	Persistent	Ex. 1, pg 59	As the COTB's main fueling yard that SNC uses is in such close proximity to our Thunder Bay operations centre (350m away), the amount of time large vehicles spent driving to refuel to an accessible gas station has significantly decreased. The cost efficiencies are calculated to be $30,331 based on 285 hours of time saved multiplied by a an hourly burdened PLT cost of $106.36.
Painting and sandblasting transformers	Capital	2022 – existing	Avoided Cost	Ex. 1, pg 60	Cost of a new 300KVA 120/208 $39,000 less the $3,500 cost of refurbishment - Avoided cost of $142,000 (Average of 4 transformers a year)

1-SEC-5

[Ex.1, p.93]

Please update Tables 1-32 and 1-33 to include full 2022 data.

SNC Response:

Please see Table 1-5 below which incorporates 2022 actual results.

TABLE 1-5: UPDATE OF COST PER CUSTOMER AND COST PER KM OF LINE

Northern Utilties / LDC's with Approximate # Of Customers Similar to SNC	Total Cost ($) per Customer					
	2017	2018	2019	2020	2021	2022*
Synergy North Corporation	$ 652	$ 678	$ 675	$ 641	$ 651	$ 755
Synergy North Corporation (Normalized)	$ 652	$ 678	$ 675	$ 673	$ 731	$ 755
Oshawa PUC Networks Inc.	$ 532	$ 569	$ 598	$ 578	$ 591	$ 638
Greater Sudbury Hydro Inc.	$ 629	$ 671	$ 679	$ 670	$ 679	$ 721
PUC Distribution Inc.	$ 673	$ 690	$ 697	$ 673	$ 696	$ 725
North Bay Hydro Distribution Limited	$ 672	$ 695	$ 732	$ 715	$ 729	$ 777
Energy Plus Inc.	n/a	$ 662	$ 677	$ 657	$ 677	$ 676
Waterloo North Hydro Inc.	$ 773	$ 819	$ 833	$ 797	$ 826	$ 711
Average	**$ 656**	**$ 684**	**$ 703**	**$ 682**	**$ 700**	**$ 708**

Northern Utilties / LDC's with Approximate # Of Customers Similar to SNC	Total Cost ($) per Km of Line					
	2017	2018	2019	2020	2021	2022*
Synergy North Corporation	$ 29,252	$ 30,585	$ 30,199	$ 28,793	$ 29,384	$ 33,928
Synergy North Corporation (Normalized)	$ 29,252	$ 30,585	$ 30,199	$ 30,375	$ 32,865	$ 33,928
Oshawa PUC Networks Inc.	$ 31,280	$ 33,915	$ 35,041	$ 34,172	$ 35,852	
Greater Sudbury Hydro Inc.	$ 29,706	$ 31,690	$ 31,938	$ 31,590	$ 31,877	
PUC Distribution Inc.	$ 30,541	$ 31,338	$ 31,775	$ 30,791	$ 31,915	$ 33,246
North Bay Hydro Distribution Limited	$ 28,233	$ 29,208	$ 30,928	$ 30,270	$ 30,857	$ 32,071
Energy Plus Inc.	n/a	$ 28,689	$ 29,569	$ 28,895	$ 29,990	$ 35,302
Waterloo North Hydro Inc.	$ 26,800	$ 28,499	$ 29,241	$ 28,166	$ 29,276	$ 31,080
Average	**$ 29,312**	**$ 30,557**	**$ 31,415**	**$ 30,647**	**$ 31,628**	**$ 32,925**

Both Energy Plus and Waterloo North Hydro Inc. were involved in consolidation in the year; as a result, the data from the new consolidated entities were used to complete the model. Waterloo North Hydro Inc's data for 2022 is that of Enova Power Corp. Energy Plus Inc's data is that of Grandbridge Energy Inc.

The cost per KM of lines for Oshawa and Greater Sudbury Hydro Inc. was excluded as their method for determining KM of lines changed in the period. Both utilities are showing a doubling of KM of service lines in 2022 without additional customers.

1-SEC-6

[Ex.1, p.100]

The Applicant states: "Starting in 2020, the corporation provided dividends to the Shareholders based on the merger savings generated". For each year since 2020, please provide the annual dividends provided to the Shareholders and the underlying basis, including full calculation, of those amounts. Please provide any information that was provided to the Applicant's shareholder to explain and/or verify the amount of merger savings generated.

SNC Response:

2020: No dividend provided to the Shareholder.

2021: SNC paid a merger efficiency dividend of $503,000 based on cumulative savings until the end of 2020. SNC calculated $79,792 in savings in 2018, $908,599 in 2019 and $866,973 in 2020 for a total initial calculation of $1,855,364. Total merger expenses incurred until 2020 agree to those presented in Exhibit 1, Table 1-36, page 102. However, for dividend purposes, the calculation excluded $139,256 of the KHEC legal and consulting costs, for a total expense of $1,169,724. The net result of these amounts, adjusted for a tax impact of 26.5%, was $503,945, rounded to $503,000.

2022: A $637,000 dividend in 2022 was based on continued savings achieved in 2021 as calculated at the time of $866,973 (actual of $859,455 as per the application page 102 Table 1-35). The after-tax impact of this was $637,255 round to $637,000.

2023: SNC paid a dividend of $300,000 in 2023. The 2023 merger dividend was based on 2022 merger savings, Exhibit 1, page 102 Table 1-35 of $847,737. Based on these savings, the anticipated dividend would have been $623,087. However, due to the additional forestry costs, and to ensure financial sustainability, SNCs Board of Directors decided to limit the dividend paid to $300,000, a reduction of $323,087.

Please see Attachment 1-3: Dividend Letters to Shareholders, for the letters provided to Thunder Bay Hydro Corp and The City of Kenora explaining the dividend.

1-SEC-7

[Ex.1, p.102]

For each operating savings shown in Table 1-35, please provide details on how the amount was calculated.

SNC Response:

TABLE 1-6: EXPLANATION OF OPERATING SAVINGS

Summary of Cumulative Annual Operating Synergies	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Forecast	Reference
PLT Reduction	115,639	115,673	130,211	121,265	154,996	A
Executive Management wages and benefits	185,719	185,719	185,719	185,719	185,719	B
Property Insurance	20,000	20,000	20,000	20,000	20,000	C
Commercial Liability Insurance		15,000	15,000	15,000	15,000	D
Kenora City Allocation	242,610	242,610	242,610	242,610	242,610	E
Customer Service Clerk	50,933	56,327	58,928	56,156	58,639	F
Billing and computer services	110,432	110,432	110,432	110,432	110,432	G
EDA membership fee reduction	17,500	17,842	18,013	18,013	18,910	H
Audit fees	27,555	27,555	27,555	27,555	27,555	I
USF Membership fees	8,750	8,750	8,750	8,750	8,750	J
Radio Licence reduction	611	611	611	611	611	K
Board Fees	8,160	8,160	8,160	8,160	8,160	L
Software Redundancy	26,466	26,466	26,466	26,466	26,466	M
Operational changes in Kenora	7,000	7,000	7,000	7,000	7,000	N
Total Operating Synergies	**$ 821,375**	**$ 842,145**	**$ 859,455**	**$ 847,737**	**$ 884,848**	

a) A PLT retired in November 2018, and the position was not filled as a result of the merger; the savings are calculated for this employee by taking the average cost of a PLT, including benefits.

b) Actual Executive Management wages, benefits and costs saved as a result of the merger, unadjusted for inflation.

c) As a result of the Merger, SNC re-evaluated Kenora's insurance policies. $20K was the actual savings associated with merging KHEC policies under SNC and also increasing the deductible associated with these policies.

d) Kenora's commercial liability was merged under the SNC brand. However, Kenora was required to remit and pay its own policy in late 2018, and as such, the savings were not achieved until 2020.

e) Total reduction in costs that were performed by the City of Kenora was $312,158 per year. However, this fee included postage on KHEC invoice. The balance was reduced by $69,548 to account for anticipated billing costs incurred by SNC.

f) As a result of the merger, TBHEDI didn't fill a Customer Service position in Thunder Bay. The annual cost of this position in 2019 was $50,933. 2020 -2023 results are based on actual average Customer Service costs in those periods.

g) Fees for activities performed by USI, and now being done internally at no additional cost to the utility, including fees associated with access to software, portal costs, and IT billing and collecting fees.

h) KHEC annual EDA membership fee was $17,500; the annual increase relates to the actual increase in fees charged by the EDA. SNC's EDA membership in 2019 was equivalent to TBHEDI 2018 rate.

i) SNC's audit fee was consistent with TBHEDI's previous audit fee; as such, the audit fees paid by KHEDI were saved upon merger.

j) USF membership fee charged to KHEC before the merger, USF fees merged into one fee post-merger, savings are persistent.

k) KHED individual radio licence, they are now under SNC's licence.

l) The costs in 2019 associated with one board member, including per diem on travel.

m) SNC was able to consolidate both service territories into one maintenance fee for its smart metering system.

n) A backhoe belonging to the former TBHEDI was transferred to Kenora as part of the merger. This allowed snow plowing and excavation to be performed internally, saving $4,000 and $3,000, respectively.

1-SEC-8

[Ex.1, Appendix 1-K, p.8]

As part of its Phase 2 Survey, the Applicant told survey participants that: “Once, all SYNERGY NORTH customers are paying the same rate for their electricity distribution, more cost efficiencies will be realized from removing the added complexity of two rates zones. The rate impact of all these efficiencies results in a rate impact reduction of $1.44 per month”. Please provide and explain the underlying calculation that shows that the Applicant expects a $1.44 per month in savings, resulting from rate harmonization.

SNC Response:

At the time SNC conducted its customer engagement, it performed Revenue Requirement and Customer Count calculation and Cost allocations based on the best information available at that time. SNC utilized SNC’s 2017 cost allocation percentages and 2021-year-end customer counts in its calculation. Utilizing the total calculated merger and operational savings based on the best information available at that time, SNC allocated those savings to customer classes based on the 2017 cost allocation. SNC allocated the savings as follows: $300K of the savings being General and Admin costs, $300K being Customer Service-related costs, and the remaining $825K being distribution-related costs. Detailed calculations are provided below in Table 1-7.

TABLE 1-7: PROJECTED SYNERGY AND RESIDENTIAL CUSTOMER IMPACT

	2024 savings	reference	Page #
Merger savings	893,999	1-staff-4	
Station savings	112,000	Exhibit 1 1.4.17	page 54
Internal truck rebuild based on 10 year useful life	7,900	Exhibit 1 1.4.17	page 55
Savings from 2023 E-billing campaign (incremental amount)	84,528	Exhibit 1 1.4.17	page 58
Automated Phone Call System	91,285	Exhibit 1 1.4.17	page 57
Reduction in internet fees	5,000		
to SNC benefit plan as they were transferred to SNC ASO benefits	30,846		
Reduction in 1 Cashier	61,225	Exhibit 1 1.4.17	page 57
Mail Clerk	9,958	Exhibit 1 1.4.17	page 57
Inter-office mail	12,000	Exhibit 1 1.4.17	page 59
Rental savings associated with move	118,776	Exhibit 1 1.4.17	page 58
Total	1,427,518		
Rounded down to	1,425,000	for calculation purposes	

Type of expense	
Distribution Cost	825,000
Customer Related Cost	300,000
G&A Cost	300,000
Capital - total value	
Capital - estimated life	25

	Residential	GS <50	General Service > 50 to 999 kW	General Service > 1000 kW	Street Light	Sentinel	Unmetered Scattered Load
OM&A	876,690	225,044	214,949	86,793	17,324	1,000	3,200
Capital							
5 year Net income	-	-	-	-	-	-	-
Annual Depreciation	-	-	-	-	-	-	-
Total Revenue Requirement	876,690	225,044	214,949	86,793	17,324	1,000	3,200
Customer Count	50,871	5,426	494	15	13,298	121	312
Impact per year	17.23	41.48	435.12	5,786.20	1.30	8.27	10.26
Impact per month	1.44	3.46	36.26	482.18	0.11	0.69	0.85

VULNERABLE ENERGY CONSUMERS COALITION (VECC)

1.0-VECC-1

Reference: Exhibit 1, page 37

"Additionally, with the exception of a merger efficiency dividend the majority shareholder has yet to receive a dividend from SNC".

a) How much was this dividend and when was it paid?

SNC Response:

a) Please see response to 1-SEC-6.

1.0 VECC-2

Reference: Exhibit 1, page 55

"In 2019, SNC purchased the Survalent Outage Management System (OMS). This technology has improved the accuracy of recording both customers affected and interruption minutes over the historical period."

a) Are the OMS and SCADA systems operable in the Kenora rate zone?

SNC Response:

a) The SCADA system in the Kenora rate zone is fully operable. The OMS system in the Kenora rate zone is not. Integrating Kenora into SNC's existing GIS database (and, therefore OMS) has been challenging due to technical limitations and legacy software. The original GIS model developed by Thunder Bay Hydro was designed specifically to map assets in UTM Zone 15; simply adding Kenora, which is in UTM Zone 16, was not possible. Conversion to a common coordinate system would mean completely rebuilding the connectivity of Thunder Bay's GIS model. Technical limitations with Survalent's OMS software are also an issue; it did not initially support multiple service areas throughout the ADMS suite and did not support automating connectivity to OMS from more than one GIS database. Survalent has responded to these limitations and is building support into their latest versions. Until these can be harmonized and SNC's legacy GIS model replaced with the modern ESRI utility networks model, SNC staff has been developing a separate

GIS database for Kenora and associated import workflows to OMS for the Kenora service area. Once completed, it will bring the Kenora service area to the same level of detail and capability as the Thunder Bay service area.

1.0-VECC-3

Reference: Exhibit 1 page 63

"SNC meets regularly with its unique Local Advisory Council (LAC), representing SNC's customers. Starting a LAC was the first of its kind in the industry"

a) Who are the members of this advisory councils. Does it include representatives from each of SNC's rate classes?

b) Does it include both Thunder Bay and Kenora representatives?

<u>SNC Response:</u>

a) Below is a list of the members on the Local Advisory Council.
   - Rob Frenette – Small Business (GU)
   - David Walsh – Residential (RS)
   - Anne-Marie Heron – Commercial (GS)
   - Lori Paras – Small Business (GU)
   - Blair Saj – Residential (RS)
   - Sila Taymaz – Residential (RS)
   - Glen Polhill – Residential (RS)
   - Lucas Jewitt – Residential (RS)
   - Hugh Briggs – Commercial (GS)

b) There are currently no Kenora members of the LAC. The council consists of any customer who wishes to participate. The council membership application is advertised through social media and SNC's website.

1.0-VECC-4

Reference: Exhibit 1, page 75 / Attachment 1-F, page 9

Performance Categories	Measures	2017	2018	2019	2020	2021	2022
Safety	Level of Public Awareness	83%	83.0%	83.0%	84.0%	84.0%	83.4%
	Level of Compliance with Ontario Regulation 22/04 (Target: substantially compliant)	C	C	C	C	C	C
	Number of General Public Incidents	0	0	0	0	0	0
	Rate per 10, 100, 1000 km of line	0	0	0	0	0	0

"Over the past six years, SNC has recorded one serious electrical incident ("Component C"). SNC's target is to achieve full compliance and to have zero serious electrical incidents."

Q15. Using the same scale, please rate your level of agreement with the following statements related to Synergy North's operations.

	Unsure	*Total Disagree*	*Neutral*	***Total Agree***
a. (Synergy North) Provides consistent, reliable electricity	1%	5%	1%	93%
b. Bills accurately	-	9%	9%	82%
c. Makes electricity safety a top priority for employees and contractors	17%	2%	2%	78%
d. Has a standard of reliability delivering electricity that meets your expectations	2%	6%	1%	91%
e. Delivers on its service commitments to customers	4%	6%	6%	84%
f. Provides excellent quality services overall	1%	6%	2%	90%
g. Quickly handles outages and restores power	1%	10%	2%	87%
h. Efficiently manages the electricity system	5%	10%	7%	78%

a) The statement and the table shown above appear to be contradictory. Synergy's Scorecard also records a Serious Electrical Incident in 2022. Please clarify and describe the noted incident including what, if any remedies were implemented subsequent to the event.

b) Among the lower scores in Synergy's customer survey is with regard to the question of employee and contractor safety. What explains these low results?

SNC Response:

a) Yes, SNC confirms there is an error in the above table. SNC Reported a *Serious Electrical Incident* to the Electrical Safety Authority as defined by Section 12 of Regulation 22/04 on August 29, 2022. This incident was reported within 48 hours after the occurrence and was a result of the contractor digging without locates. The contractor was excavating when they pulled an SNC underground energized cable up and out of the ground, which subsequently pulled that cable out of the associated pad mount transformer. This resulted in damage to the cable and the transformer, but there were no injuries to the contractor or the public as a result of the digging. SNC has reiterated to this contractor that locates are required whenever the soil is being disturbed.

b) The lower score on the questions with regard to employer and contractor safety appears to be skewed by the % of customers who answered "unsure." Only 2% of customers "totally disagreed," which is low in relation to other responses. SNC continues to target public safety initiatives based on survey results in efforts to eliminate all incidents and further inform the public regarding electrical safety and SNC's commitment to it.

1.0-VECC-5

Reference: Exhibit 1, Attachment 1-F, page 13

Q19. Regarding customer service at Synergy North, how would you rate your level of satisfaction with each of the following?

	Unsure	Total Dissatisfied	Neither satisfied nor dissatisfied	Total satisfied 2022	Total satisfied 2021
a. The availability of call centre staff	3%	4%	6%	87%	84%
c. The online self-serve options for managing your account	23%	6%	13%	58%	55%
d. The online self-serve options for requesting service	24%	12%	9%	54%	52%

a) What steps is SNC taking to address the poor results with respect to on-line account management?

SNC Response:

a) SNC disagrees with the premise that these are poor results, with only 6% of customers dissatisfied with SNC performance. However, SNC always striving to improve and has purchased and is in the process of completing the implementation of a new customer portal. The previous portal was unavailable to offer customers expanded features such as Green Button certification. In addition, SNC undertook a review of customer processes in 2021 from a customer journey perspective. This exercise changed several processes. One example identified was to provide customers with a welcome 'package' in the form of an email which outlined what online services are available to customers. This was intended to address customers who were unsure of what SNC was offering online.

CONSUMERS COUNCIL OF CANADA

1-CCC-1

Ex. 1

Please provide copies of all documents that were provided to the Board of Directors related to the Application, Business Plan and the underlying budgets.

SNC Response:

SNC's Board of Directors approved the capital and operating budgets underpinning this Application on January 26, 2023. The Board of Directors was provided with the 2022-2024 Business Plan (Exhibit 1, Attachment 1-C), as well as the 2024 Budget presentation (Exhibit 1, Attachment 1-D SNC 2024 Budget). Additional documents provided to the Board of Directors with regards to an update to SNC's Business Plan and the approval of the underlying budgets in 2023 and 2024 are provided as Attachment 4-3.

1-CCC-2

Ex. 1/p. 27

Was there any rate harmonization evidence discussed/addressed during the amalgamation proceeding? If so, what were the nature of that evidence? If not, why not? Please provide all internal studies produced regarding SNC's rate harmonization proposals. What rate harmonization proposals were considered and rejected. Is it SNC's position that rate harmonization is required at this time?

SNC Response:

Yes, it is SNC's position that rate harmonization is required at this time. Section 2.8.13 of the Chapter 2 Filing Requirements states that distributors that have been part of a MAADs transaction and that have not yet had a rate harmonization plan approved by the OEB for their distribution service areas must file a rate harmonization plan (see also page 21 of the Handbook for Utility Rate Applications). In addition, the Handbook to Electricity Distributor and Transmitter Consolidations directs at page 17 that: "A consolidated entity is expected to propose rate structures and rate harmonization plans following consolidation at the time it files its rebasing application. Distributors are not required to file details of their rate-setting plans, including any proposals for rate harmonization, as part of the application for consolidation. These issues will be addressed at the time of rate rebasing of the consolidated entity."

In accordance with this guidance, SNC indicated in its MAAD application EB-2018-0124 that (a) two separate rate classes would only continue until the deferred rebasing (see Section 2.2.4.1 page 26); and (b) future rates for both rate zones will be set by the Annual IR Index or Price Cap Methodology for Kenora Hydro and Thunder Bay Hydro rate zones respectively during the 5 year rebasing deferral period. There is no need to consider rates issues in this proceeding (see section 2.2.6.2 at page 50).

Harmonization will create additional future efficiencies that will benefit customers in both service territories by reducing the duplication of work performed by staff by maintaining two rate zones. Future efficiencies and additional capacity will be achieved as resources will not need to be added to complete the required increasing work to maintain two separate rate zones.

EB-2018-0124 page 50 stated "that future rates for both rate zones will be set by the Annual IR index or Price Cap Methodology for Kenora Hydro and Thunder Bay Hydro rate zones respectively during the 5 years rebasing deferral period. There is no need to consider rates issues in this proceeding."

1-CCC-3

Ex. 1/p. 36

Please provide a complete description of the activities undertaken by Thunder Bay Hydro Utility Services. Does it provide services to SNC? Are the employees part of SNC? What other utilities does it provide services to?

SNC Response:

Activities undertaken by Thunder Bay Hydro Utility Services (TBHUSI) include:

Meter Service Provider (MSP): Provides primary metering services to other utilities and corporations.

Locate Services: The locates services consist of back-office administration as well as field locates services performed by qualified Damage Prevention Technicians.

Back-office services for other Northern LDCs: Activities such as downloading meter reading data, wholesale settlement, electronic business transaction functions, remote meter reader function, smart meter services, CDM services, information services, customer information services, accounting and regulatory services and purchasing services.

The employees used to perform these services are paid through SNC but billed directly to the affiliates for their time working on USI projects.

TBHUSI does not provide services to SNC. The list of customers that TBHUSI provides services to is not relevant to the matters at issue in the proceeding and responding would have the effect of disclosing sensitive confidential information of a competitive affiliate that is not regulated by the Ontario Energy Board.

1-CCC-4

Ex. 1/p. 39 Figure1.2

Please explain the roles and responsibilities of the Customer & Renewable Energy Coordinator.

SNC Response:

A Summary of Duties:

- Manage escalated customer inquiries and the process to resolve customer complaints to bring these issues to closure in a timely fashion.
- Establish key account relationships with community partners, commercial businesses, advocacy groups and other representative groups to determine needs and provide guidance.
- Understand and be able to convey commercial billing structures and available programs for customers as they relate to SNC bills.
- Develop account plans for each established key account to meet the desired targets of SNC or the customer. These plans are based on dollars saved or emissions reduced.
- Responsible for SNCs solar PV assets.

1-CCC-5

Ex. 1/pp. 50-51

Please explain the extent to which adverse weather events have impacted the 2024 OM&A Capital and distribution revenue in 2024.

SNC Response:

To ensure system resilience, SNC has implemented several practices across divisions, such as replacing aging infrastructure, installing automated components, and developing business continuity and emergency action plans. Ex. 2, Attachment 2-A SNC DSP Section 5.3.1.2.6 Page 43 discuss these practices and investments. Although these investments improve resiliency and mitigate the impact of weather-related events, this is not their primary driver but rather an additional benefit. For example, SNC's primary driver for replacing aging infrastructure is due to their failure risk and health and safety hazard, and a secondary driver is reliability. Should SNC experience any adverse weather effects, it has prepared by participating in shared inventory and mutual assistance programs, has regular testing of backup generators at its main operations site and emergency action plans.

The positive benefits of the SNC capital program relating to adverse weather or a bi product of the work being performed, SNC is not budgeting to undertake any capital work which is solely as a result of the adverse weather. There is no revenue requirement impact as a result.

SNC budgets costs related to responding to adverse weather events in its OM&A accounts, and 4-AMPCO-30 details Storm Damage Repair costs for each of the years 2017 to 2024. SNC is budgeting $279,938 and $282,638 respectively in 2023 and 2024 relating to adverse weather events. The $282,638 corresponds to the revenue requirement ask in this application.

1-CCC-6

Ex. 1/p. 52

Please explain the extent to which the electrification of transportation has impacted the 2024 revenue requirement.

SNC Response:

Ex. 2, Attachment 2-A SNC DSP Section 5.2.1.2.1 Page 8 states that "SNC does not expect significant electrification of transportation or fuel switching will factor into the next 5-year term. It does expect to see a few early adopters, which will not affect the number of connections that SNC typically experiences". See 1-Staff-3 for a listing of the initiatives that SNC has undertaken to prepare for the electrification of transportation.

1-CCC-7

Ex. 1/p. 54

Please provide a detailed breakdown of the $33.3 million in cost savings related to the conversion of the 4kV and subsequent decommissioning of the remaining substations. What is the impact on the 2024 revenue requirement.

SNC Response:

Thunder Bay Hydro Electricity Distribution Inc (TBHEDI) submitted documentation in 2013 in its Asset Management Plan (AMP), which estimated the cost savings related to the conversion of 4kV. (EB-2012-0167), see Attachment 1-4: 4kV Conversion. Below is a detailed breakdown of the $33.3M in cost savings related to the conversion and subsequent decommissioning of the remaining substations.

TABLE 1-8: SUBSTATION REPLACEMENT ESTIMATE

Distribution Station Component	Estimated Cost to Rebuild a 4kV Substation in 2023
4MVA, 24.94kV/4.16kV, Oil Immersed Power Transformer (Qty 2)	$1,648,000
4kV, 1200A Breaker Lineup (8 Breakers/Substation Average)	$3,500,000
Total	$5,148,000
The total of 7 stations must be replaced from 2023 to 2028. The present value of their replacement at 2% CPI equals ($5,148,000 per station)	$33,683,548
The total net present value of avoided decommission costs of the replacing 7 stations at 2% CPI ($57,888 per station)	($370,839)
Total avoided cost of replacing 7 stations	$33,312,709 or rounded as $33.3M

The above analysis was performed to validate the business case for decommissioning 4kV substations that was a consideration in preparing the DSP. However, as part of the work completed in 2023, one additional station will no longer be needed. The following rate impact will be based on the state of the system at the time of the IRs.

The rate impact in 2024 is based on the difference in capital and OM&A expenditure that would need to occur in the test year if the plan to convert to 25kV was eliminated. SNC would be required to replace one of its substations in 2024 at a cost of $5,148,000. However, 40% of the poles scheduled for replacement would no longer be required based on the asset conditioning report—a reduction in 4kV work of $2,887,726. Additional station maintenance would be required, an amount calculated to be $28,000 per station. As such, the 2024 Revenue requirement was calculated as follows:

TABLE 1-9: 2024 4KV CONVERSION REVENUE REQUIREMENT SAVINGS

2024 Impact		
Average Net Book Value	1,122,445	
Working capital increase	2,100	
Rate Base Increase	1,124,545	
Total Revenue Requirement		**129,774**

* Assumes depreciation and CCA are the same

The more significant savings were anticipated to impact customers at the end of the conversion project, as it avoids having to rebuild six stations over the next four years. In addition, there are anticipated OM&A savings over the period as well. The estimated additional Revenue requirement that would be required in 2029 if the 4kV conversion is not completed is calculated as follows:

TABLE 1-10: 2024 – 2029 4KV CONVERSION REVENUE REQUIREMENT SAVINGS

2029 Impact		
Average Net Book Value	19,171,830	
Working capital increase	185,486	
Rate Base Increase	19,357,316	
Total Revenue Requirement		**2,021,583**

The 2029 revenue requirement is based on one station being built in 2024, one in 2025, two in 2026 and two in 2027. However, by maintaining the 4kV system, pole replacement over the next 4 years would be reduced by $10,750,074.

1-CCC-8

Ex. 1/p. 55

The evidence states that SNC has achieved productivity and cost efficiencies with its fleet since the last COS through using fleet utilization data to make more efficient decisions regarding fleet purchases etc. What is the impact on the 2024 revenue requirement of SNC's fleet strategy?

SNC Response:

Please refer to SNC's response to 1-SEC-4, which quantifies the efficiencies achieved with regard to fleet. Current revenue requirement savings are in the form of reduced capital spending both in the past and in the future. Since 2017 SNC has avoid the following capital expenditures.

Two old single buckets that had failed dielectric testing were repurposed as chassis for new flat deck trucks, saving $200,000 in capital additions.

These two single buckets would have also required replacement if the 4kV system was being continued, with savings of $230,000 in 2020 and $245,000 in 2021.

Two additional single bucket trucks used on the 4kV system would have also required replacement in 2023 and 2024 for $260,000 and $275,000, respectively.

A stock factory double bucket truck was purchased, instead of a custom build in 2021 resulting in $60,000 in further capital savings.

The total revenue requirement savings as a result of this avoid capital was $146,788.

TABLE 1-11: REVENUE REQUIREMENT SAVINGS AS A RESULT OF FLEET EFFICIENCIES

Description			Revenue Requirement
Total eliminated Rate Base Addition @2023	841,833		
Total eliminated Rate Base Addition @2024	1,026,833		
Rate Base Impact		$ 934,333	
Return on Debt			24,185
Return on Equity			34,981
Additional PILS requirement*			12,612
Depreciation			75,000
			$ 146,778
* assumes depreciation and CCA are the same			

1-CCC-9

Ex. 1/p. 58

For each year, 2024-2028 what is the expected percentage of customers on e-billing. What are the expected cost savings in each year?

SNC Response:

SNC has experienced an average 2.9% increase in customers on e-billing year to year since 2017. The estimated cost savings per customer on e-billing is based on this historical increase. The cost savings per customer per year on e-billing is approximately $12.

TABLE 1-12: E-BILLING COST SAVINGS

	2024	2025	2026	2027	2028
Total % of customers forecasted on e-billing	20,133	21,100	22,778	24,456	26,134
Cost Savings	$241,602	$253,209	$273,343	$293,476	$313,610

1-CCC-10

Ex. 1/p. 64

Did SNC discuss with its customers the proposed distribution rate increases set out in the application? Did SNC, as part of its customer engagement, indicate that its proposed Return on Equity embedded in 2024 rates would be approximately 9%? If not, why not?

SNC Response:

Yes, SNC discussed the proposed the rate increases through the Have Your Say Synergy North Phase One & Phase Two public surveys. The surveys were included as Attachment 1-K in our filed Exhibit 1 application. Specifically, Questions 6 through 12 in Phase 2 of SNC's Have Your Say Survey focused solely on proposed rate increases, broken down by what is driving those increases in each question. A revised version of question 12 has been submitted as Attachment 1-5: Phase 2 Survey. The verbiage to the Kenora question was incorrectly pasted to the Thunder Bay survey for filing purposes only. Thunder Bay customers would have seen the correct version during the survey.

SNC did not specifically indicate that its proposed ROE would be approximately 9% as the ROE is established by the OEB and is not subject to change based on customer input. It is noted that customer input is important when considering SNC management and operating decisions.

1-CCC-11

Ex. 1/p. 83

Please explain, in detail, why SNC's cost per customer has increased significantly since 2017. Why has the cost per customer not decreased since the merger?

SNC Response:

Impacting SNC's total cost per customer are increases in Capital (Spending, Cost of Capital and OEB Formulaic costs) and OM&A increases (Forestry, Cyber Security spending)

Capital Increases: Impact on cost per customer is $171. The calculation of the capital costs used in the PEG benchmarking is based on three factors, Rate of Return, a formulaic Capital Price, and a formulaic Capital Quantity. The Breakdown of these factors are:

Capital Price: In 2017 the formulaic capital priced used in the benchmarking study was $17.04 based on inflationary increases over the last 7 years, this value is projected to be 22.94 in 2024. This projection is based on increases of 3.63% in 2023 2.27% in 2024 (March 31, 2023, TB Bank inflation expectation (Exhibit 1 page 82 lines 8- 12)). The ultimate impact of these increases is $87 per customer.

Rate of Return: The impact the in the growth of the rate of return value used in the 2017 calculation of 5.67% vs the rate used in the application of 6.67% has resulted in $45 of the increased cost per customer.

Capital Quantity: This formulaic value considers the utilities total gross additions each and reduces this value by a set 4.59% depreciation rate. Since 2017 SNC capital quantity has grown by 129,906 units, resulting in an additional cost to customer of $39. This growth is attributable to our planned capital; however, refer to response to 1-CCC-7 for a description of the anticipated savings over the next Cost of Service cycle as a result of these plans and $5.5M in recovered unplanned capital between 2019-2022 performed on behalf of the City of Kenora, The City of Thunder Bay and two fiber internet expansion projects with Tbaytel and Bell.

OM&A increases: Impact on cost per customer is $26. Included in the 2022, 2023 and 2024 costs are $1.35M in additional Forestry funding as discussed in SNC's Tree Trimming and Vegetation Management plan Exhibit 4, 4.3.3.5 – Vegetation Management Program. In addition, SNC has an additional $153,725 and $140,893 of Cyber spending, respectively in the Bridge and Test years, which also impacts this calculation. These costs represent an increase of $26 per customer. Excluding the above additions, budgeted 2024 OM&A costs have only increased 11% over 2017 actuals, a figure significantly below actual OEB inflation of 20.2% for the same period.

1-CCC-12

Ex. 1/p. 83

Please explain, in detail, why the cost per Km of line has increased since 2017 significantly. What steps is SNC tsking to improve this metric?

SNC Response:

Please see SNC's response to 1-CCC-11 for a description of the drivers of the increase in cost per KM as the drivers of the increase in cost per KM are the same as those driving the increase in cost per customers.

SNC continues to operate the utility in the most efficient way possible, constantly creating efficiencies wherever possible including consolidation of rental space, and elimination of staffing positions through efficiencies, please see 1-SEC-4 for a detailed list of efficiencies earned over the last seven years. SNC is continuing its 4kV conversion program over the next 5 years, a program that will allow SNC to avoid an additional capital spend of $22 M (which is the $33.3M saved on station rebuilds less $10.7M in assets being replaced early) for the replacement of six station assets, a figure that would significantly increase the Cost per Customer and Cost per KM in the future. As a result of its forecasted capital program, SNC was able to create its fleet plan, as discussed in Appendix E, page 421, in Exhibit 2SNC Vehicle and Equipment Resource Justification Plan 2023, with additional efficiencies. These changes will have an impact on both the Cost per Customer and Cost per KM of Line during the 4th Generation IRM period.

1-CCC-13

Ex. 1/pp. 101-103

Re: Amalgamation Decision (EB-2018-0124/0233) pp. 7-8

In the Decision that approved the amalgamation there are references to expected cost savings;

•The Applicants provided a comparison of Operating, Maintenance and Administration (O&M) costs for a scenario where there is no amalgamation (i.e. the status quo) versus the post amalgamation scenario over the proposed five year deferred rebasing period (2019 to 2023 inclusive). The comparison provided by the Applicants demonstrated that the amalgamated entity when compared to the status quo costs of both Thunder Bay Hydro and Kenora Hydro;

•The Applicants noted negligible capital savings arising from the proposed amalgamation. As a result, capital savings were not included in the cost comparison between status quo and post-amalgamation scenarios. When the Applicants were asked by OEB Staff to describe any capital savings anticipated from the proposed amalgamation following the deferred rebasing period, the Applicants stated that capital expenditures or savings could not be predicted. The Applicants noted that LDC Mergeco will need to review and work on incorporating the Kenora Hydro distribution assets into the existing Thunder Bay Distribution System Plan. Until this thorough review is undertaken, capital expenditures or savings cannot be predicted;

•The Applicants estimate OM&A synergies over the 5-year deferral period to total $3.8 million with transaction costs totalling $1.4 million;

•The Applicants submit that OM&A savings, as identified in the application are expected to result in lower cost structures for LDC Mergeco at the time of first rebasing relative to the status quo and the savings – approximately $900,000 per year – will continue in perpetuity.

a) Please provide the comparison referred to in the first point;
b) Please provide the review referred to in the second point;
c) Please provide a breakdown of the $3.8 million in projected synergies. Please provide the actual synergies on the same basis;
d) Please provide a breakdown of the $1.4 million in transition and transaction costs. Please provide the actual transition and transaction costs on the same basis;
e) Please provide a breakdown of the $900,000 in annual savings projected in the amalgamation proceeding. Please provide a breakdown of the $884,000 of sustained savings on the same basis.
f) Did SNC achieved capital savings? If so, please identify those savings.

SNC Response:

a) Please see Table 1-13 below for a summary of savings.

TABLE 1-13: PROJECTED YEAR OVER YEAR COMPARATIVE COST STRUCTURE ANALYSIS

1		2018	2019	2020	2021	2022	2023
2	OM&A	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
3	Thunder Bay Hydro	15,989,680	16,245,515	16,505,443	16,769,530	17,037,843	17,310,448
4	Kenora Hydro	2,099,360	2,126,652	2,154,298	2,182,304	2,210,674	2,239,413
5	Consolidated OM&A Status Quo	18,089,040	18,372,167	18,659,741	18,951,834	19,248,517	19,549,861
6							
7	OM&A Synergies	(800,000)	(260,220)	864,551	877,816	889,227	900,787
8	Post Consolidation	18,889,040	18,632,387	17,795,191	18,074,019	18,359,289	18,649,074

b) Please see Attachment 1-6: KMTS Survey. In addition, SNC did a review of the system; as a result of this review, an additional $1M of underground work was done in Kenora due to significant defects that were discovered. To help mitigate these additional costs, SNC was able to reduce Kenora's general plant and equipment by sending a single bucket truck, a backhoe with a rock breaker, an F250 Crew Cab with a topper, and a pole trailer from Thunder Bay's fleet to Kenora vs buying these assets.

c) Please see table 1-14 below.

TABLE 1-14: SUMMARY OF PROJECTED CUMULATIVE ANNUAL OPERATING SYNERGIES PER MAAD

Summary of Cumulative Annual Operating Synergies PER MAAD	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	Cumulative
Clerk	$ 69,676	$ 69,676	$ 70,582	$ 71,500	$ 72,429	$ 353,863
IT Costs	$ 2,914	$ 2,914	$ 2,952	$ 2,990	$ 3,029	$ 14,798
Office Expenses	$ 4,052	$ 4,052	$ 4,105	$ 4,158	$ 4,212	$ 20,579
Travel	$ 28,364	$ 18,234	$ 18,471	$ 18,711	$ 18,954	$ 102,735
Absorbed Control cost	$ 3,069	$ 3,069	$ 3,109	$ 3,150	$ 3,191	$ 15,588
Billing and Customer Service	$ 59,702	$ 217,611	$ 220,440	$ 223,306	$ 226,209	$ 947,269
Training	$ 22,691	$ 22,691	$ 22,986	$ 23,285	$ 23,588	$ 115,241
Entertainment and meals	$ 1,520	$ 1,520	$ 1,539	$ 1,559	$ 1,580	$ 7,717
Engineering Costs	$ 46,797	$ 46,797	$ 47,405	$ 48,021	$ 48,646	$ 237,666
CEO costs	$ 98,771	$ 197,541	$ 200,109	$ 202,711	$ 205,346	$ 904,477
Telephone IP		$ 8,104	$ 8,209	$ 8,316	$ 8,424	$ 33,054
Audit, Outside Legal and Reg Costs		$ 61,649	$ 62,451	$ 63,262	$ 64,085	$ 251,447
PLT reduction		$ 212,692	$ 215,457	$ 218,258	$ 221,095	$ 867,502
Total Synergies per MAAD	$ 337,556	$ 866,550	$ 877,815	$ 889,227	$ 900,787	$ 3,871,936

Table 1-35: – Summary of Operating Synergies

Summary of Cumulative Annual Operating Synergies as per Exhibit 1 Table 1-35	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Forecast	Cumulative
PLT Reduction	115,639	115,673	130,211	121,265	154,996	$637,784
Executive Management wages and benefits	185,719	185,719	185,719	185,719	185,719	$928,595
Property Insurance	20,000	20,000	20,000	20,000	20,000	$100,000
Commercial Liability Insurance		15,000	15,000	15,000	15,000	$60,000
Kenora City Allocation	242,610	242,610	242,610	242,610	242,610	$1,213,050
Customer Service Clerk	50,933	56,327	58,928	56,156	58,639	$280,983
Billing and computer services	110,432	110,432	110,432	110,432	110,432	$552,159
EDA membership fee reduction	17,500	17,842	18,013	18,013	18,910	$90,278
Audit fees	27,555	27,555	27,555	27,555	27,555	$137,775
USF Membership fees	8,750	8,750	8,750	8,750	8,750	$43,750
Radio Licence reduction	611	611	611	611	611	$3,055
Board Fees	8,160	8,160	8,160	8,160	8,160	$40,800
Software Redundancy	26,466	26,466	26,466	26,466	26,466	$132,330
Operational changes in Kenora	7,000	7,000	7,000	7,000	7,000	$35,000
Total Operating Synergies	**$ 821,375**	**$ 842,145**	**$ 859,455**	**$ 847,737**	**$ 884,848**	**$ 4,255,559**

d) Please see Table 1-15 below.

TABLE 1-15: SUMMARY OF TRANSITION COSTS PER MAAD APPLICATION AND SUMMARY OF ACTUAL TRANSITION COSTS

Summary of Transaction and Transition Costs Per MAAD Application	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	Cumulative
Project Manager Costs	-	100,000	100,000	2,000	$218,647
Billing and Customer Service Costs	-		136,485		$136,485
Severance Fees	-		361,291		$402,302
Regulatory and legal costs	-	700,000			$700,000
Totals	**$ -**	**$ 800,000**	**$ 597,776**	**$ 2,000**	**$ 1,457,434**

Summary of Transaction and Transition Costs as per Exhibit 1 Table 1-36	**2017 Actuals**	**2018 Actuals**	**2019 Actuals**	**2020 Actuals**	**Cumulative**
Legal and Consulting - TBHC/SNC	157,463	321,909	290,557	-	$786,576
Legal and Consulting - KHEC	94,787	45,110		-	$139,897
Adminstration & Other Costs	357	482	129	-	$41,979
Travel and Board Fees	3,575	12,777	47,389	-	$63,741
Telephone, Postage and Internet charges	326	4,197	30,059	-	$34,582
Promotion and Advertising	-	9,605	56,696	-	$67,381
Application fees			5,209	-	$5,209
Wages and Benefits	1,129	159,216	-	-	$160,345
Supplies	-	2,180	7,090	-	$9,270
Totals	**$ 257,637**	**$ 555,476**	**$ 437,129**	**$ -**	**$ 1,308,980**

e) Please see the 2023 forecast amounts as listed under part c) above.

f) SNC had savings in fleet acquisitions as discussed in part c) above.

ASSOCIATION OF MAJOR POWER PRODUCERS (AMPCO)

1-AMPCO-1

Ref: Ex.1 p. 22

While the actual level of work and targeted volume of work between 2017 and 2024 (650 assets vs 630 assets) is not significantly different, the complexity of the renewal areas combined with increases in material and labour costs have contributed to the overall increase in system renewal.

On the same basis, please provide the targeted volume of work in terms of assets over the 2024 to 2028 period.

SNC Response:

a) SNC is targeting a levelized approach to asset replacement for the forecast period.

- 2024 = 630
- 2025 = 615
- 2026 = 615
- 2027 = 615
- 2028 = 615

1-AMPCO-2

Ref: Ex. 1 p. 53

SNC discusses productivity and cost reductions.

Please provide a schedule that sets out the OM&A and capital productivity savings for the years 2017 to 2024.

SNC Response:

Please refer to the response for 1-SEC-4.

1-AMPCO-3

Ref: Ex.1 p. 86

At current rates, SNC has a revenue deficiency in 2024.

a) Please confirm the revenue deficiency at the time of filing interrogatory responses.

b) Please provide a schedule that sets out the material drivers of the revenue deficiency.

SNC Response:

a) Please see Table 1-16 below.

TABLE 1-16 REVISED REVENUE DEFICIENCY CALCULATION

Description	2024 Test at Existing Rates	2024 Test - Required Revenue
Revenue		
Revenue Deficiency		$7,181,432
Distribution Revenue	$28,550,675	$28,550,675
Other Operating Revenue (Net)	$2,794,697	$2,794,697
Total Revenue	**$31,345,372**	**$38,526,804**
Costs and Expenses		
OM&A Expenses	$21,434,661	$21,434,661
Depreciation & Amortization	$6,138,149	$6,138,149
Deemed Interest	$4,162,767	$4,162,767
Total Costs and Expenses	**$31,735,576**	**$31,735,576**
Utility Income Before Income Taxes	-$390,204	$6,791,228
Corporate Income Taxes	$0	$908,422
Utility Net Income	**-$390,204**	**$5,882,806**
Income Tax Expense Calculation:		
Accounting Income	-$390,204	$6,791,228
Tax Adjustments to Accounting Income	-$3,363,222	-$3,363,222
Taxable Income	**-$3,753,426**	**$3,428,006**
Income tax expense before credits	**$0**	**$908,422**
Credits	$0	$0
Income Tax Expense	$0	$908,422
Tax Rate Reflecting Tax Credits	26.50%	26.50%
Actual Return on Rate Base:		
Rate Base	$159,685,294	$159,685,294
Interest Expense	$4,162,767	$4,162,767
Net Income	-$390,204	$5,882,806
Total Actual Return on Rate Base	**$3,772,563**	**$10,045,573**
Actual Return on Rate Base:	2.36%	6.29%
Deficiency/Sufficiency in Rate of Return	-3.93%	
Revenue Deficiency After Tax	**$6,273,010**	**-$0**
Revenue Deficiency Before Tax	**$7,181,432**	**-$0**

b) Please see Table 1-17 below.

TABLE 1-17 REVISED REVENUE DEFICIENCY BY REVENUE REQUIREMENT COMPONENT

Description	Last Rebasing Year - 2017 - Board Approved Proxy "A"	2024 Allocation "B"	2024 Test Year "C"	Revenue Deficiency vs 2023 existing rates "D" = "C" - "B"	Variance vs 2017 Board Approved Proxy "E" = "C" - "A"	% Variance "E"/"A"	Reference
OM&A, including LEAP & Property Taxes	$17,328,455	$19,803,422	$21,434,661	$1,631,239	$4,106,205	23.7%	Exhibit 4 - 4.2.2
Depreciation	$4,111,788	$4,699,061	$6,138,149	$1,439,087	$2,026,361	49.3%	Exhibit 2 -2.4
Payments in Lieu of Corporate Income Tax (PILs)	$299,646	$342,444	$908,421	$565,977	$608,775	203.2%	Exhibit 6 - 6.5
Return on Debt	$1,445,198	$1,651,611	$4,162,767	$2,511,155	$2,717,568	188.0%	Exhibit 5 -5.2.1-5.2.4
Return on Equity	$4,242,843	$4,848,834	$5,882,806	$1,033,972	$1,639,964	38.7%	Exhibit 5 - 5.2.5
Total	**$27,427,931**	**$31,345,372**	**$38,526,804**	**$7,181,432**	**$11,098,873**	**40.5%**	
Rate Base	**$119,888,205**		**$159,570,594**		**$39,682,389**	**33.1%**	

1-AMPCO-4

Ref: EB-2018-0124 s.86 (MAADs) Application p. 30 Figure 8

Figure 8 below provides a comparison of the cost structure among the Parties, status quo versus post consolidation.

Figure 8 – Year over Year Comparative Cost Structure Analysis

1		2018	2019	2020	2021	2022	2023
2	OM&A	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
3	Thunder Bay Hydro	15,989,680	16,245,515	16,505,443	16,769,530	17,037,843	17,310,448
4	Kenora Hydro	2,099,360	2,126,652	2,154,298	2,182,304	2,210,674	2,239,413
5	Consolidated OM&A Status Quo	18,089,040	18,372,167	18,659,741	18,951,834	19,248,517	19,549,861
6							
7	OM&A Synergies	(800,000)	(260,220)	864,551	877,816	889,227	900,787
8	Post Consolidation	18,889,040	18,632,387	17,795,191	18,074,019	18,359,289	18,649,074

Please update Figure 8 with Actuals.

SNC Response:

The following Table 1-18 updates Figure 8 with Actual results up to 2022 and projected results for 2023.

TABLE 1-18: SNC OM&A ACTUAL VS. OM&A WITHOUT MERGER

	2017 Year -1	2018 Year 0	2019 Year 1	2020 Year 2	2021 Year 3	2022 Year 4	2023 Year 5
Consolidated Status Quo	17,690,155	17,314,189	17,484,307	17,258,496	17,145,914	20,772,248	21,246,296
Synergy Savings	-	-	821,375	842,145	859,455	847,737	884,848
Synergy Costs	(257,637)	(555,476)	(437,129)	-	-	-	-
OM&A Synergies	(257,637)	(555,476)	384,246	842,145	859,455	847,737	884,848
Post consolidation	**17,947,792**	**17,869,665**	**17,100,061**	**16,416,351**	**16,286,459**	**19,924,511**	**20,361,448**

After TBHEDI and KHEC merged in 2019, SNC did not separate OM&A costs between Thunder Bay and Kenora region. Actual OM&A synergies and merger transaction costs are found in SNC's Exhibit 1, Table 1-35 and 1-36. Please refer to Exhibit 4, Figure 4.3: Actual OM&A vs. OM&A Without Merger for what actual OM&A expenses would have been on a "Consolidated OM&A Status Quo" basis.

ATTACHMENT 1-1:

Response to Letters of Comment

November 10, 2023

Re: SYNERGY NORTH Corporation ("SNC") – Cost of Service Filing – Letters of Comment

A Huzan,

Thank you for your message with respect to SNC's proposed Cost of Service Application for rates effective May 1, 2024. Your feedback and engagement is appreciated.

SNC continues to strive for efficiencies in everything it does. SNC has earned an efficiency rating of cohort 3 annually since inception (2019), based on the OEB cost benchmarking model, which indicates continual performance in line with expected values. SNC anticipates that this ranking will continue in the future, even with additional rate impacts.

SNC is aware of the challenges of a fixed distribution charge on customers, especially residential customers and strives to keep this cost as low as possible. Customers should be aware that SNC does not produce power, as it is a distribution company. Further, SNC, as a distributor, doesn't make or lose money on the sale of power (commodity) and must abide by the ordered pricing decisions.

Ontario Local Distribution Companies (LDC) typically apply to the Ontario Energy Board every 5 years to approve rates for the following year. These applications are on a five-year cycle, with a detailed Cost of Service review in year 1, followed by inflationary adjustments in years 2 to 5.

The Ontario Energy Board will only approve an increase in distribution rates if SNC can provide adequate evidence to support and justify its underlying costs. SNC does take into account the current economic and societal climate as part of its application and operations and an electricity distributor is not immune from the impacts (such as increased capital cost, supply chain issues and inflationary cost pressure) while working to meet customer expectations.
SNC understands that customers have been impacted by the COVID-19 pandemic and increasing inflation and that some are also worried about the cost of electricity. To support customers most impacted, SNC will continue to invest in external communications to increase awareness of existing support programs and resources such as the Ontario Energy Rebate (OER); the Low-Income Energy Assistance Program - Emergency Financial Assistance (LEAP EFA); and Save On Energy programs, as well as future support programs/ resources available. SNC will continue to educate customers on available resources, energy conservation, and customer choice.

Thank you again for your comments and please contact us again should you have questions or require further information.

Respectfully Submitted, Synergy North Corporation.

34 CUMBERLAND STREET NORTH | THUNDER BAY, ON | P7A 4L4 | T: (807) 343-1111 | 1-833-428-1451 synergynorth.ca

November 10, 2023

Re: SYNERGY NORTH Corporation (“SNC”) – Cost of Service Filing – Letters of Comment

R Mancuso,

Thank you for your message with respect to SNC’s proposed Cost of Service Application for rates effective May 1, 2024. Your feedback and engagement is appreciated.

SNC is aware of the challenges of a fixed distribution charge on customers, including both small business owners and low-income individuals. SNC continues to find efficiencies in everything it does and strives to keep this cost as low as possible.

SNC understands that customers have been impacted by the COVID-19 pandemic and increasing inflation and that some are also worried about the cost of electricity. To support customers most impacted, SNC will continue to invest in external communications to increase awareness of existing support programs and resources such as the Ontario Energy Rebate (OER); the Low-Income Energy Assistance Program - Emergency Financial Assistance (LEAP EFA); and Save On Energy programs, as well as future support programs/ resources available. SNC will continue to educate customers on available resources, energy conservation, and customer choice.

Ontario Local Distribution Companies (LDC) typically apply to the Ontario Energy Board every 5 years to approve rates for the following year. These applications are on a five-year cycle, with a detailed Cost of Service review in year 1, followed by inflationary adjustments in years 2 to 5.

The Ontario Energy Board will only approve an increase in distribution rates if SNC can provide adequate evidence to support and justify its underlying costs. SNC does take into account the current economic and societal climate as part of its application and operations, and an electricity distributor is not immune from the impacts (such as increased capital cost, supply chain issues and inflationary cost pressure) while working to meet customer expectations.

SNC has earned an efficiency rating of cohort 3 annually since inception (2019), based on the OEB cost benchmarking model, which indicates continual performance in line with expected values. SNC anticipates that this ranking will continue in the future, even with additional rate impacts.

Thank you again for your comments and please contact us again should you have questions or require further information.

Respectfully Submitted, Synergy North Corporation.

34 CUMBERLAND STREET NORTH | THUNDER BAY, ON | P7A 4L4 | T: (807) 343-1111 | 1-833-428-1451 synergynorth.ca

November 10, 2023

Re: SYNERGY NORTH Corporation ("SNC") – Cost of Service Filing – Letters of Comment

TW Jewell, 2565784 Ontario Inc.

Thank you for your message with respect to SNC's proposed Cost of Service Application for rates effective May 1, 2024. Your feedback and engagement is appreciated.

To address some of your specific concerns:

- SNC used inflation factors of 3.7% in 2023 and 2% in 2024 as per Exhibit 4, page 19 in its application, the 6.8% was simply a statement of what CPI was at the time SNC was preparing its 2024 budget.
- With regards to increasing costs, SNC continues to find efficiencies if everything it does. SNC has earned an efficiency rating of cohort 3 annually since inception (2019), based on the OEB cost benchmarking model, which indicates continual performance in line with expected values. SNC anticipates that this ranking will continue in the future, even with additional rate impacts.
- Per Exhibit 1, page 61-68, SNC describes all customer engagement activities undertaken since its last Cost of Service application. Customers had the opportunity to participate in two "Have Your Say" customer engagement surveys over 2022 and 2023 that were used to obtain feedback and obtain consultation on its draft investment plan. In addition, SNC has a Local Advisory Council that meets on a regular basis to discuss varying issues, including the investment plan and vegetation management plan included in SNC's Cost of Service Application. This council is always looking and encouraging new members to join.

Ontario Local Distribution Companies (LDC) typically apply to the Ontario Energy Board every 5 years to approve rates for the following year. These applications are on a five-year cycle, with a detailed Cost of Service review in year 1, followed by inflationary adjustments in years 2 to 5.

The Ontario Energy Board will only approve an increase in distribution rates if SNC can provide adequate evidence to support and justify its underlying costs. SNC does take into account the current economic and societal climate as part of its application and operations and an electricity distributor is not immune from the impacts (such as increased capital cost, supply chain issues and inflationary cost pressure) while working to meet customer expectations.

SNC is aware of the challenges of a fixed distribution charge on customers, especially residential customers and strives to keep this cost as low as possible. Customers should be aware that SNC as a distributor doesn't make or lose money on the sale of power (commodity) and must abide by the ordered pricing decisions.

SNC understands that customers have been impacted by the COVID-19 pandemic and increasing inflation, and that some are also worried about the cost of electricity. To support customers most impacted, SNC

34 CUMBERLAND STREET NORTH | THUNDER BAY, ON | P7A 4L4 | T: (807) 343-1111 | 1-833-428-1451 synergynorth.ca

will continue to invest in external communications to increase awareness of existing support programs and resources such as the Ontario Energy Rebate (OER); the Low-Income Energy Assistance Program - Emergency Financial Assistance (LEAP EFA); and Save On Energy programs, as well as future support programs/ resources available. SNC will continue to educate customers on available resources, energy conservation, and customer choice.

Thank you again for your comments and please contact us again should you have questions or require further information.

Respectfully Submitted, Synergy North Corporation.

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November 10, 2023

Re: SYNERGY NORTH Corporation ("SNC") – Cost of Service Filing – Letters of Comment

T Jewell,

Thank you for your message with respect to SNC's proposed Cost of Service Application for rates effective May 1, 2024. Your feedback and engagement is appreciated.

SNC understands that customers have been impacted by increasing inflation and that some are also worried about the cost of electricity. SNC continues to strive for efficiencies in everything that we do. SNC has earned an efficiency rating of cohort 3 annually since inception (2019), based on the OEB cost benchmarking model, which indicates continual performance in line with expected values. SNC anticipates that this ranking will continue in the future, even with additional rate impacts.

To support customers most impacted, SNC will continue to invest in external communications to increase awareness of existing support programs and resources such as the Ontario Energy Rebate (OER); the Low-Income Energy Assistance Program - Emergency Financial Assistance (LEAP EFA); and Save On Energy programs, as well as future support programs/ resources available. SNC will continue to educate customers on available resources, energy conservation, and customer choice.

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Thank you again for your comments and please contact us again should you have questions or require further information.

Respectfully Submitted, Synergy North Corporation.

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ATTACHMENT 1-2:

Corporate Balanced Scorecards

Thunder Bay Hydro Electricity Distribution Inc.
Board of Director's Corporate Evaluation Criteria

STRATEGIC OBJECTIVE – HEALTH & SAFETY

Thunder Bay Hydro's primary Long-Term Corporate Goal is to '**Ensure that the Health and Safety of our Employees and the Public is the Utility's first priority'.**

As a utility, we will strive to prevent all incidents that might result in loss through personal injury, occupational illness or damage to property by continuously improving our Corporate Occupational Health & Safety (OHS) system.

DESCRIPTION

Senior Management is committed to safety excellence and will drive the agenda by establishing and maintaining a vision that outlines an ongoing and improving state of safe operation. All line managers will be personally involved with safety improvement objectives and performance audits. Continual efforts will be made to ensure a Culture of Safety permeates the organization.

2017 OBJECTIVES	TARGET DATE(S)
• Zero Lost Time Injuries (alternatively: Lost Time Incident and Severity result trends that compare favourably to comparative industry benchmarks)	Quarterly/Yearly
• Maintain positive performance trend for vehicle incidents, medical aid, dig-up, near miss incidents	Yearly
• Cultivate a culture where Safety is of primary importance	Ongoing
• Enhance External Health & Safety Programs through program delivery and community participation	Ongoing
• Enhance staff Health & Wellness Programs through program delivery	Ongoing

FIRST QUARTER UPDATE

• Zero Lost Time Incidents in Q1	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good	On Target
• Significant Health & Wellness and Safety training undertaken in Q1	On Target
• Limited scheduled external activity in Q1. Focus on internal training.	On Target

SECOND QUARTER UPDATE

• One Lost Time Incidents in Q2	Target not achieved
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats very good	On Target
• Scheduled Health & Wellness and Safety training undertaken in Q2	On Target
• Significant external activity in Q2.	On Target

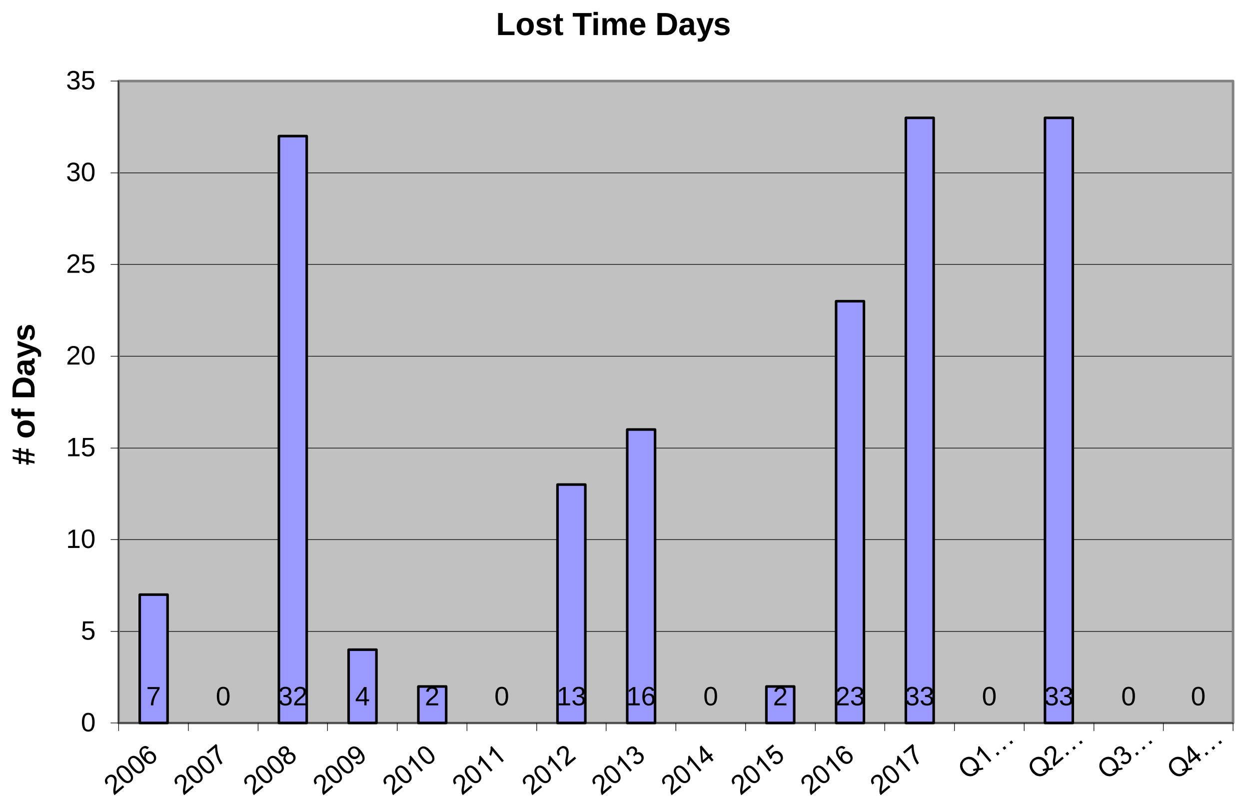
THIRD QUARTER UPDATE

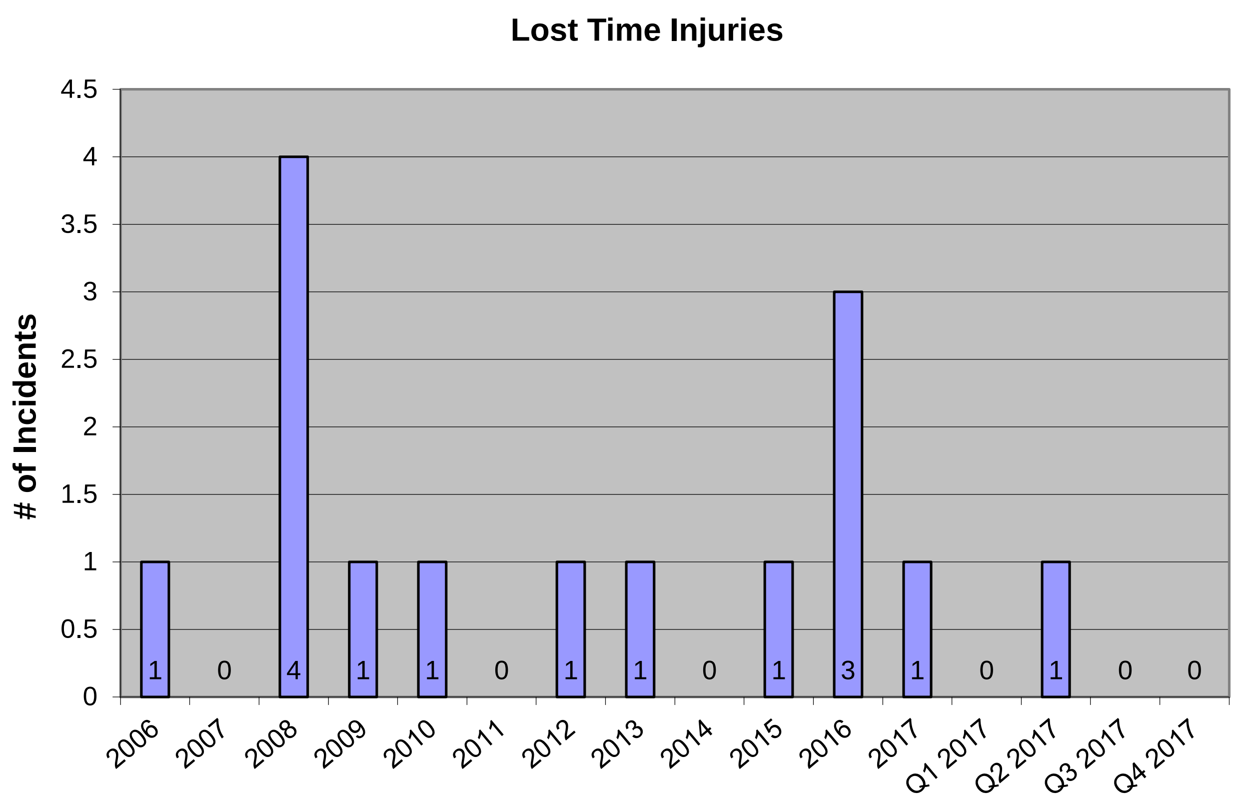
• Zero Lost Time Incidents in Q3	Quarterly Target achieved
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats very good	On Target
• Limited scheduled Health & Wellness and Safety training undertaken in Q3	On Target
• Limited external activity in Q3.	On Target

FINAL QUARTER UPDATE

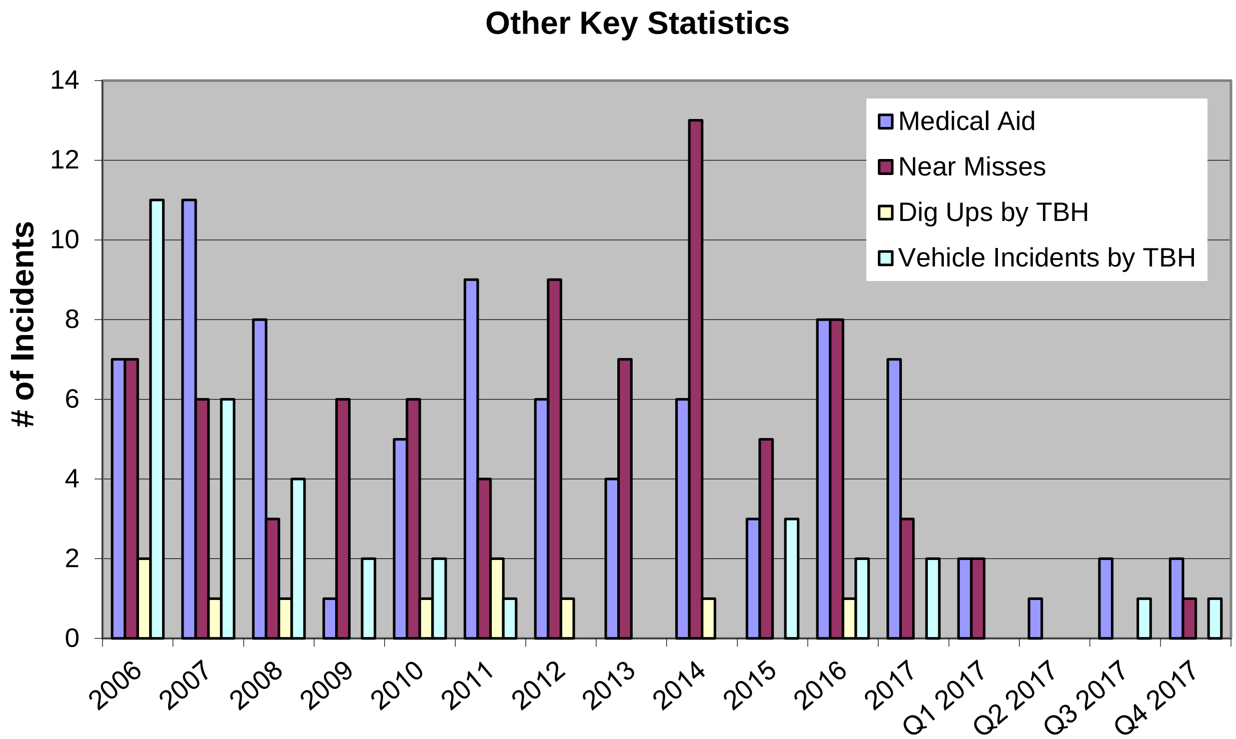
• Zero Lost Time Incidents in Q4	Quarterly Target achieved
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats very good	On Target
• Scheduled Health & Wellness and Safety training undertaken in Q4	On Target
• Scheduled external activity delivered in Q4.	On Target

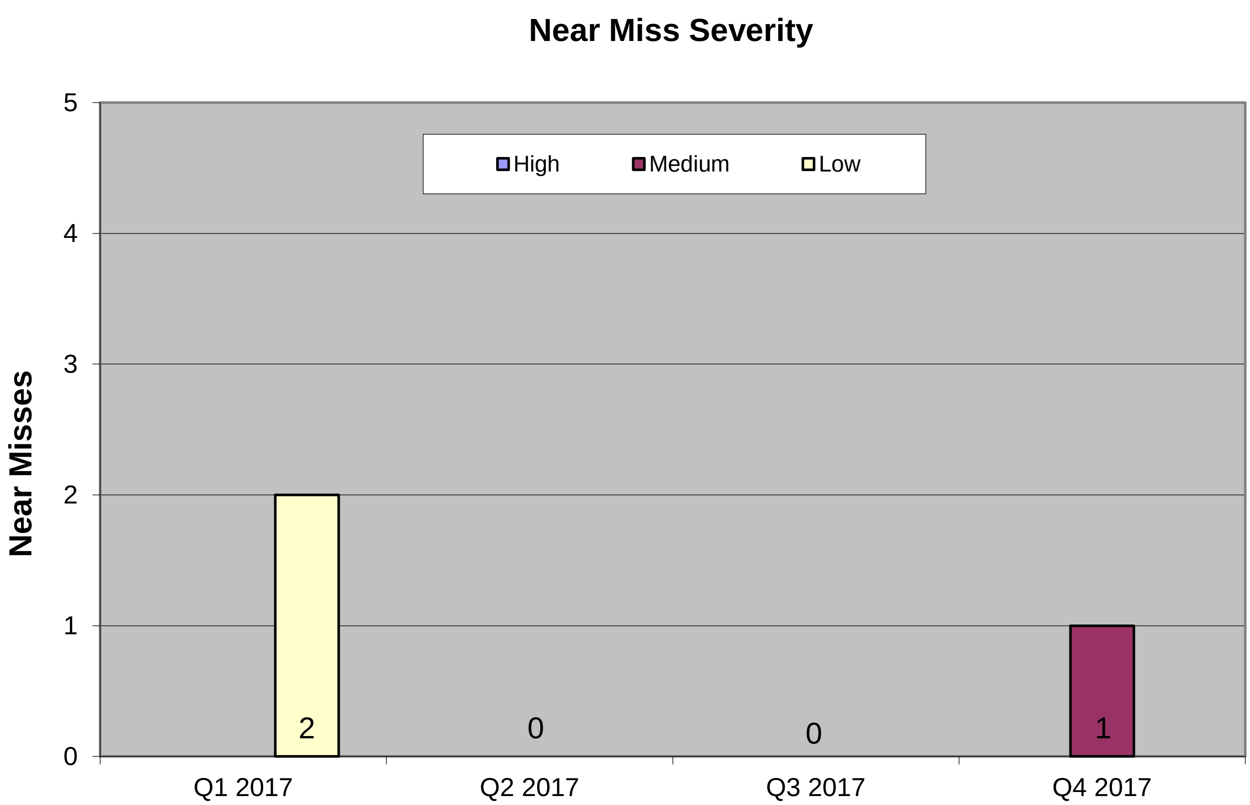
Historical Safety Statistics





Historical Safety Statistics





Thunder Bay Hydro Electricity Distribution Inc.
Board of Director's Corporate Evaluation Criteria

STRATEGIC OBJECTIVE – FINANCIAL PERFORMANCE MEASURES

Financial Performance Evaluation allows the Board to monitor the financial performance of the utility relative to budgeted and historical measures. Provides a high level overview of the financial health of the organization and facilitates the exercise of the Board's financial due diligence.

DESCRIPTION

- Monthly O&M Expenditures compared to budget, previous year and available industry benchmarks
- Capital Expenditures compared to budget and previous year
- Distribution Revenue compared to budget and previous year
- Presentation of key financial ratios

2017 OBJECTIVES	TARGET DATE(S)
• Manage Controllable Expenses to 2016 Budget levels	Q4 2016
• Manage Capital Expenditures to 2016 Budget level	Q4 2016
• Maintain financial ratios above minimum threshold (Subject to change to reflect impact of specific strategic initiatives)	Ongoing

FIRST QUARTER UPDATE

• OM&A Expenses slightly above budget	On Target
• Distribution Revenue slightly ahead of budget at Q1	On Target
• Q1 CapEx expenditures slightly behind plan	On Target
• Financial Ratios in acceptable range	On Target

SECOND QUARTER UPDATE

• OM&A Expenses slightly below budget	On Target
• Distribution Revenue below budget at Q2 – COS impact	On Target
• Q2 CapEx expenditures slightly behind plan – COS impact	On Target
• Financial Ratios in acceptable range	
• On Target	

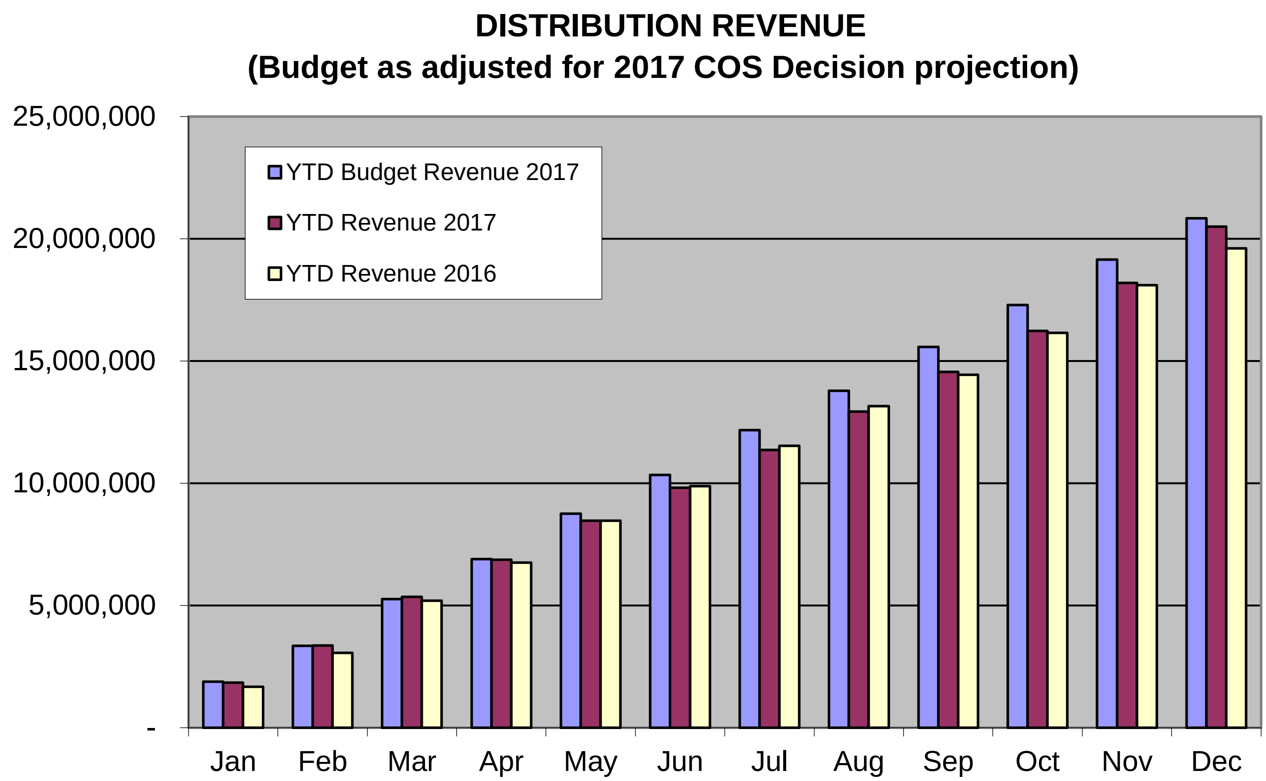
THIRD QUARTER UPDATE

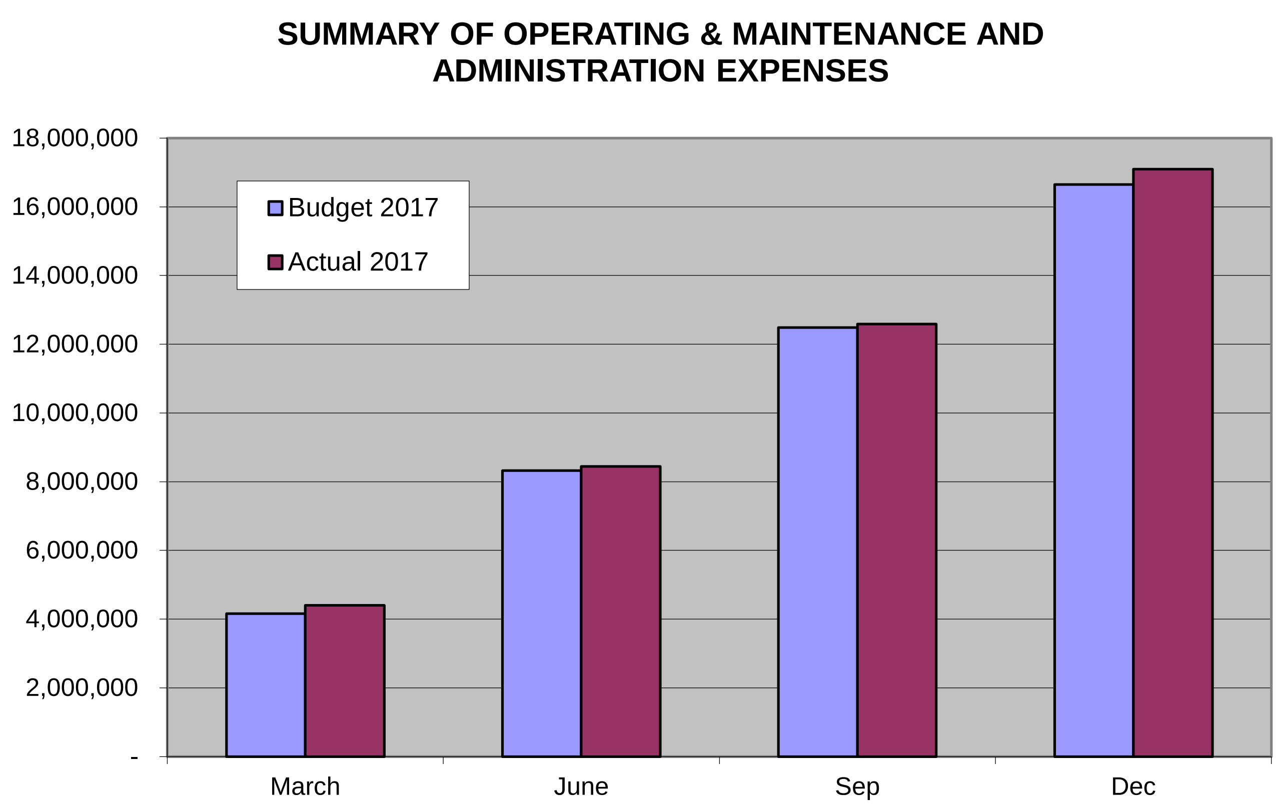
• OM&A Expenses very slightly above budget to end of Q3	On Target
• Distribution Revenue below budget at Q3 – COS impact	On Target
• Q3 CapEx expenditures behind plan – COS impact	On Target
• Financial Ratios in acceptable range	On Target

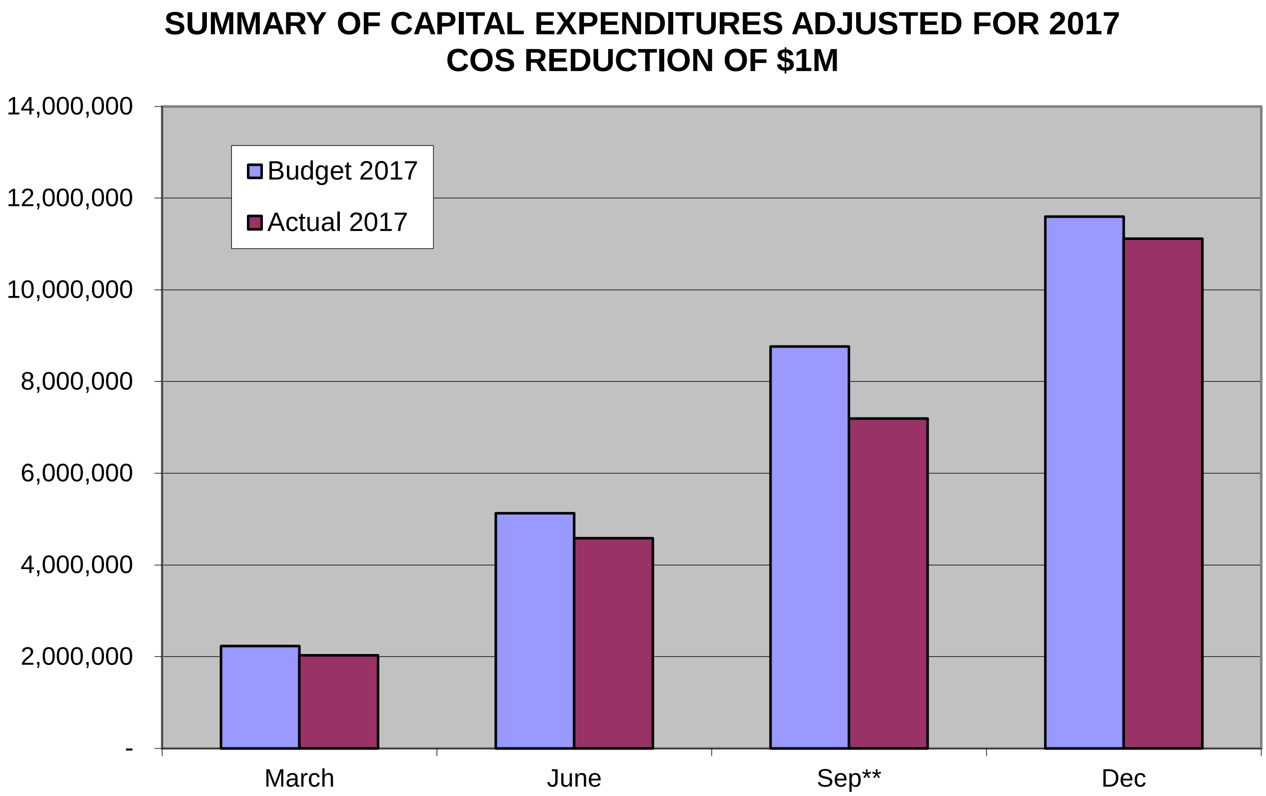
FINAL QUARTER UPDATE

• OM&A Expenses above budget to end of Q4 – unbudgeted COS/merger impact	On Target
• Distribution Revenue below budget at Q4 – COS impact	On Target
• Q4 Planned CapEx expenditures achieved on budget	On Target
• Financial Ratios in acceptable range	On Target

Year To Date Summary Financial Results







Year To Date Summary Financial Results

Ratios as at December 30, 2017		Goal/ Requirement
Working Capital Ratio	1.75	> 1.00:1
Quick Ratio	1.65	> 1.00:1
Debt Capitalization Ratio	0.47	< 0.60:1
Bank Debt Capitalization Ratio	0.28	
Debt Service Coverage - TD	1.49	>1.2:1

Thunder Bay Hydro Electricity Distribution Inc.
Board of Director's Corporate Evaluation Criteria

STRATEGIC OBJECTIVE – OPERATIONAL PERFORMANCE MEASURES

One of Thunder Bay Hydro's Long-term Corporate Goals is to '**Provide a reliable supply of electricity to the residents and businesses of Thunder Bay'.**

Operational Performance Measures allow the Board to monitor the ongoing electricity reliability performance of the utility compared to historical performance. The Board can also monitor the ongoing operational performance of the utility as compared to Ontario Energy Board's Service Quality Indicator targets.

DESCRIPTION

- Monthly reliability indices as compared to previous years, available industry data and regulatory requirements
- Year to date Service Quality Indicators performance compared with targets established by the OEB

2017 OBJECTIVES	TARGET DATE(S)
• Reliability indices within the 5 year range of historical performance	Ongoing
• Service Quality Indicators meet/exceed OEB requirements	Ongoing
• Other internal measures as identified or developed in the future (i.e.: CDM program delivery, specific productivity factors, etc.)	Ongoing

FIRST QUARTER UPDATE

• Q1 Reliability Statistics compare well to historical	On Target
• All YTD OEB Service Indicator levels exceeded in Q1	On Target
• CDM programs in market	On Target
• Q1 CapEx projects on schedule	On Target

SECOND QUARTER UPDATE

• Q2 Reliability Statistics compare well to historical	On Target
• All YTD OEB Service Indicator levels exceeded in Q2	On Target
• CDM programs in market – LU CHP work ongoing	On Target
• Q2 CapEx projects on schedule – other Capex delayed – COS impact	On Target

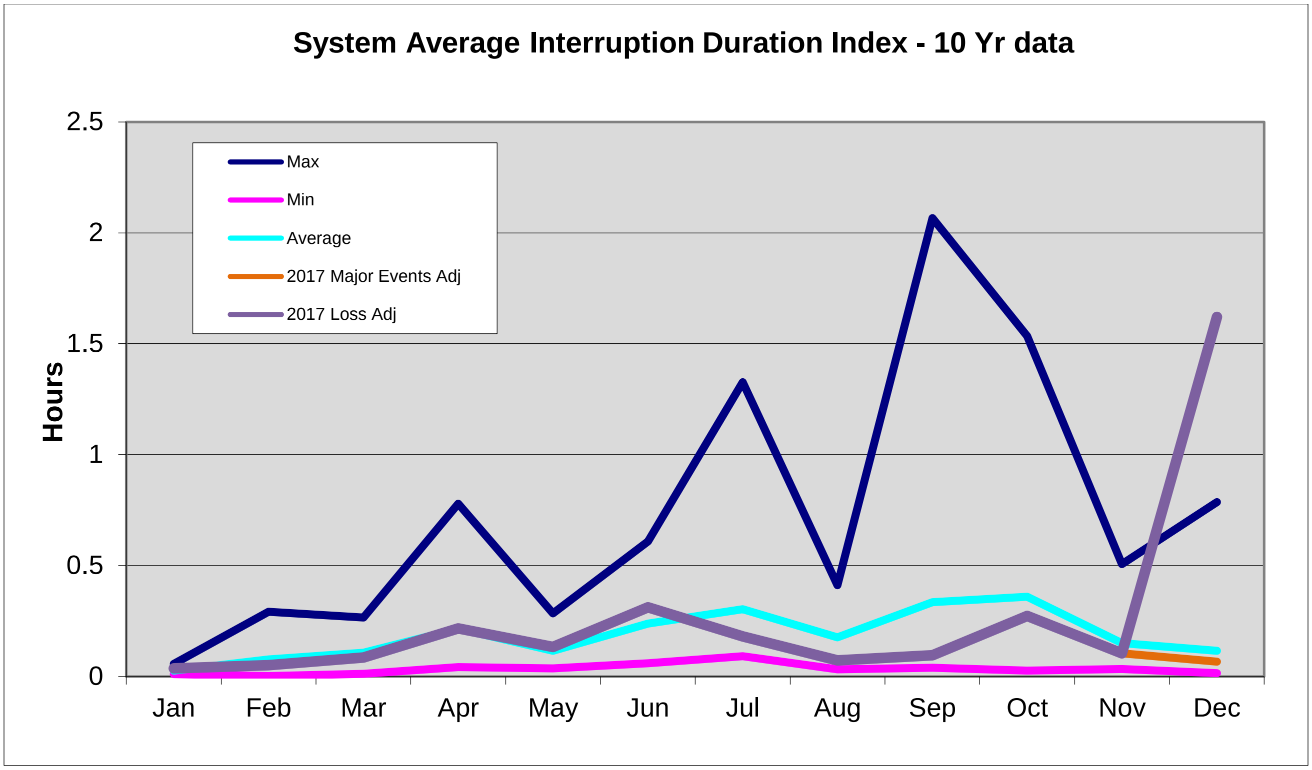
THIRD QUARTER UPDATE

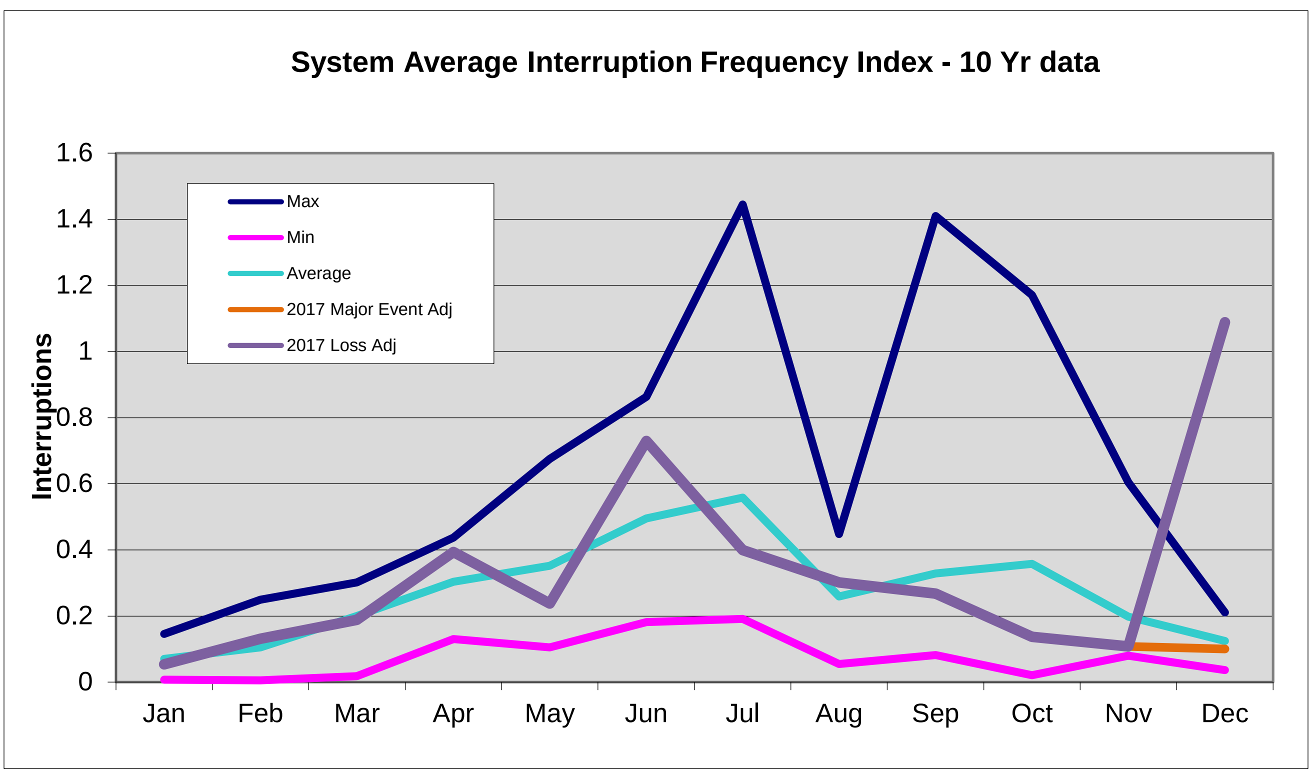
• Q3 Reliability Statistics compare well to historical	On Target
• All YTD OEB Service Indicator levels exceeded in Q3	On Target
• CDM programs in market – LU CHP work ongoing	On Target
• Q3 CapEx projects on schedule – other Capex delayed – COS impact	On Target

FINAL QUARTER UPDATE

• Q4 Reliability Statistics compare well to historical – extreme weather event adjust	On Target
• All YTD OEB Service Indicator levels exceeded in Q4	On Target
• CDM programs in market – LU CHP project cancelled – custom program in market	On Target
• Q4 CapEx projects on schedule	On Target

Year To Date Operational Performance Indices





Year To Date Operational Performance Indices

Customer Service Performance Indicators	Annual %	Standard %	Months Below Standard
New Service Connection-low voltage	100	90	0
New Service Connection-high voltage	100	90	0
Underground Cable Locates	97	90	0
Telephone Accessibility	94.81	65	0
Appointments Met	96.2	90	0
Written Responses to inquiries	100	80	0
Emergency Response-Urban areas	93	80	0
Emergency Response-Rural areas	97.92	80	0

Thunder Bay Hydro Electricity Distribution Inc.
Board of Director's Corporate Evaluation Criteria

STRATEGIC OBJECTIVE – HEALTH & SAFETY

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DESCRIPTION

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2018 OBJECTIVES	TARGET DATE(S)
• Zero Lost Time Injuries (alternatively: Lost Time Incident and Severity result trends that compare favourably to comparative industry benchmarks)	Quarterly/Yearly
• Maintain positive performance trend for vehicle incidents, medical aid, dig-up, near miss incidents	Yearly
• Cultivate a culture where Safety is of primary importance	Ongoing
• Enhance External Health & Safety Programs through program delivery and community participation	Ongoing
• Enhance staff Health & Wellness Programs through program delivery	Ongoing

FIRST QUARTER UPDATE

• Zero Lost Time Incidents in Q1	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good	On Target
• Significant Health & Wellness and Safety training undertaken in Q1	On Target
• Limited scheduled external activity in Q1. Focus on internal training.	On Target

SECOND QUARTER UPDATE

• Zero Lost Time Incidents in Q2	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good – strong near miss reporting	On Target
• Significant Health & Wellness and Safety training undertaken in Q2	On Target
• Strong Public Safety Initiative program in Q2	On Target

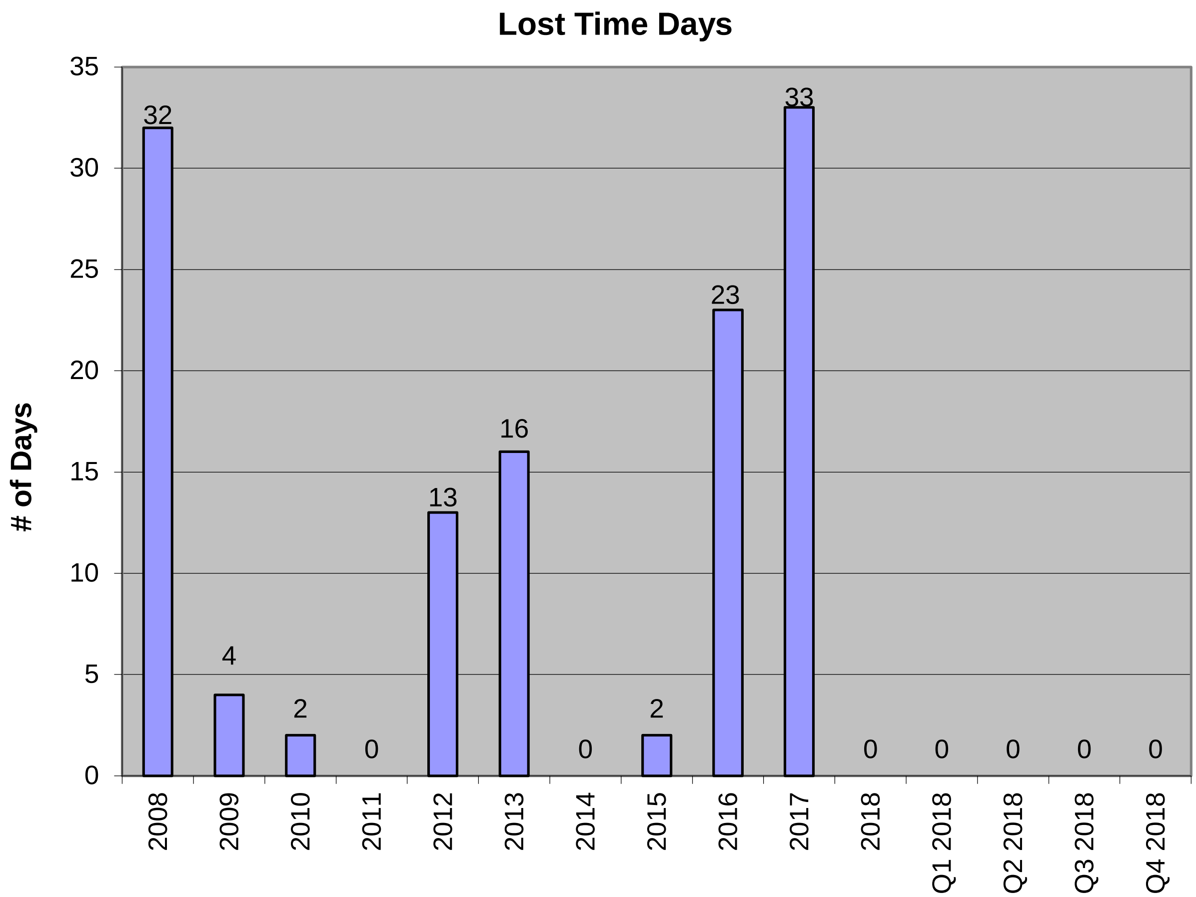
THIRD QUARTER UPDATE

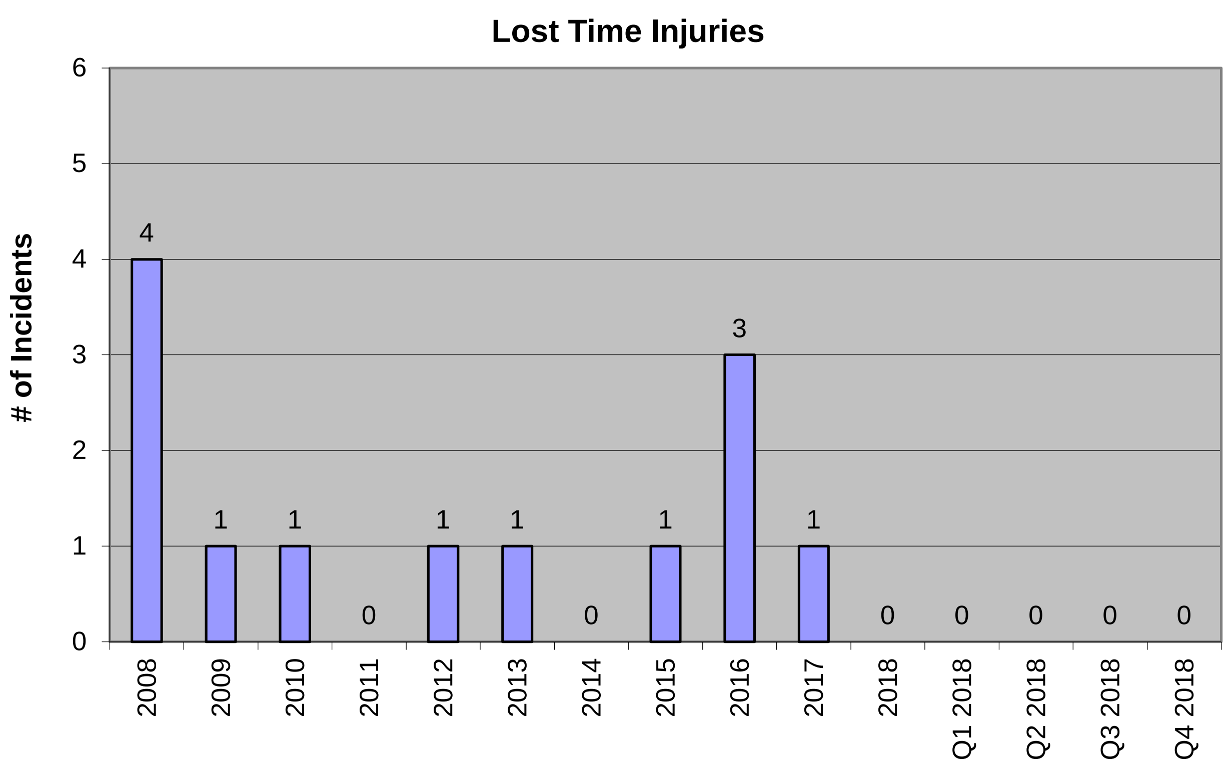
• Zero Lost Time Incidents in Q3	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good – strong near miss reporting	On Target
• Reduced schedule of Health & Wellness and Safety training undertaken in Q3	On Target
• Continued Public Safety Initiative program delivery in Q3	On Target

FINAL QUARTER UPDATE

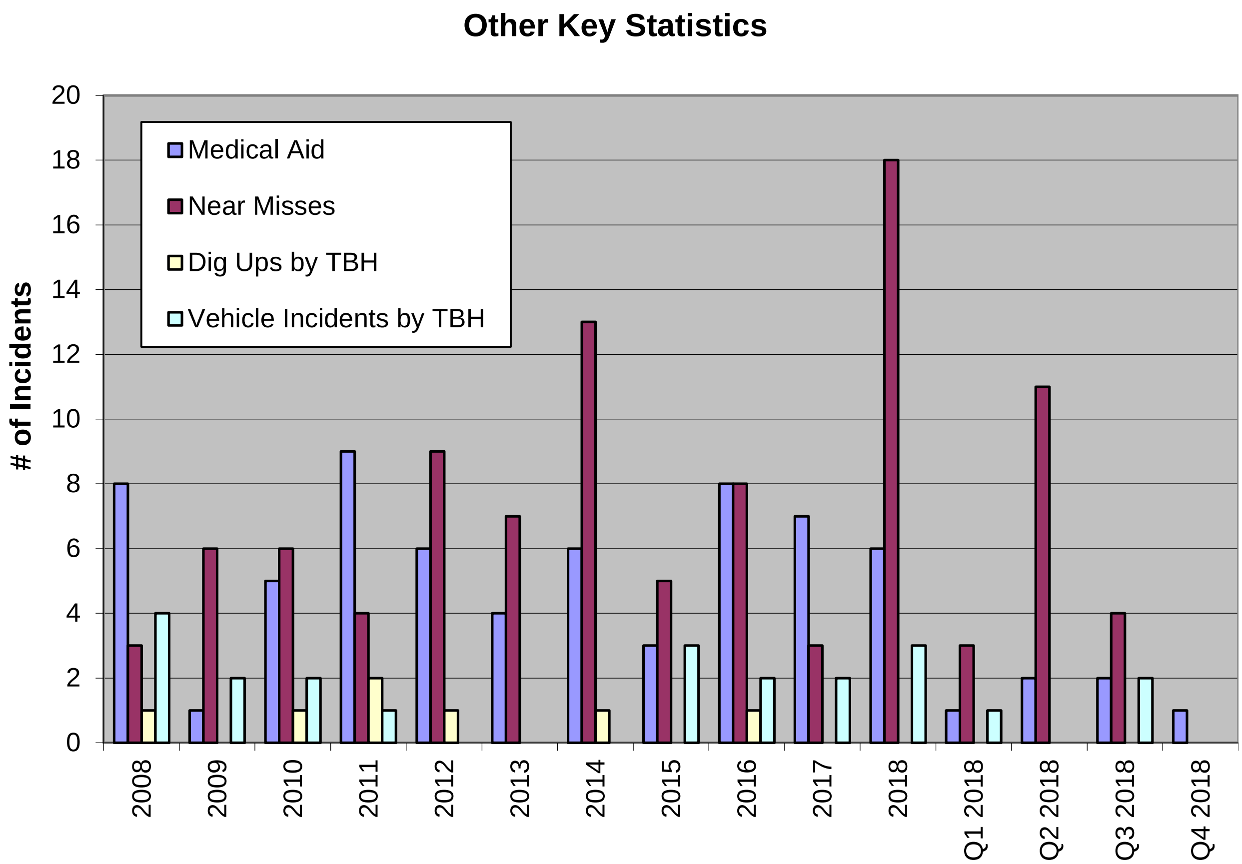
• Zero Lost Time Incidents in Q4	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good – strong near miss reporting	On Target
• Scheduled Health & Wellness and Safety training delivered in Q4	On Target
Continued Public Safety Initiative program delivery in Q4	On Target

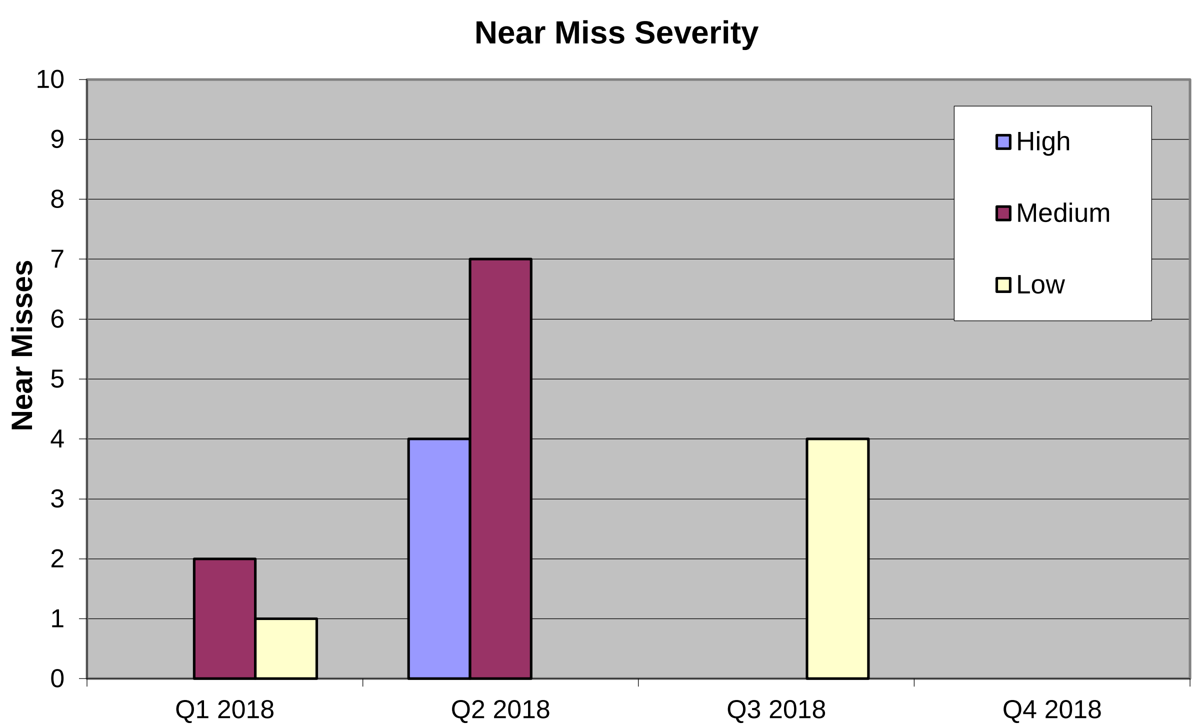
Historical Safety Statistics





Historical Safety Statistics





Thunder Bay Hydro Electricity Distribution Inc.
Board of Director's Corporate Evaluation Criteria

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DESCRIPTION

- Monthly O&M Expenditures compared to budget, previous year and available industry benchmarks
- Capital Expenditures compared to budget and previous year
- Distribution Revenue compared to budget and previous year
- Presentation of key financial ratios

2018 OBJECTIVES	TARGET DATE(S)
• Manage Controllable Expenses to 2018 Budget levels	Q4 2018
• Manage Capital Expenditures to 2018 Budget level	Q4 2018
• Maintain financial ratios above minimum threshold (Subject to change to reflect impact of specific strategic initiatives)	Ongoing

FIRST QUARTER UPDATE

• OM&A Expenses very slightly above budget at Q1	On Target
• Distribution Revenue slightly below budget at Q1	On Target
• Q1 CapEx expenditures slightly ahead of plan	On Target
• Financial Ratios in acceptable range	On Target

SECOND QUARTER UPDATE

• OM&A Expenses very slightly above budget at Q2 – merger costs	On Target
• Distribution Revenue slightly below budget at Q2	Under Target
• Q2 CapEx not provided – projects on plan	N/A
• Financial Ratios not provided	N/A

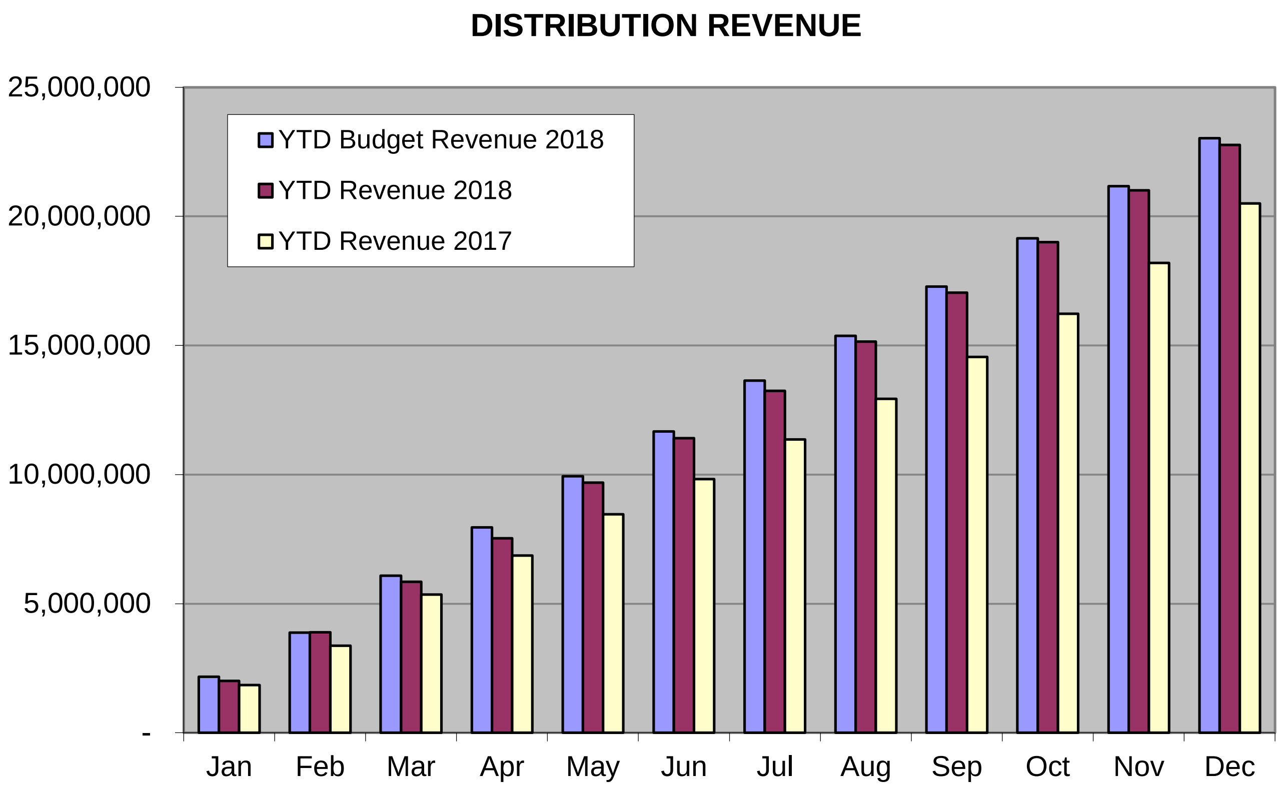
THIRD QUARTER UPDATE

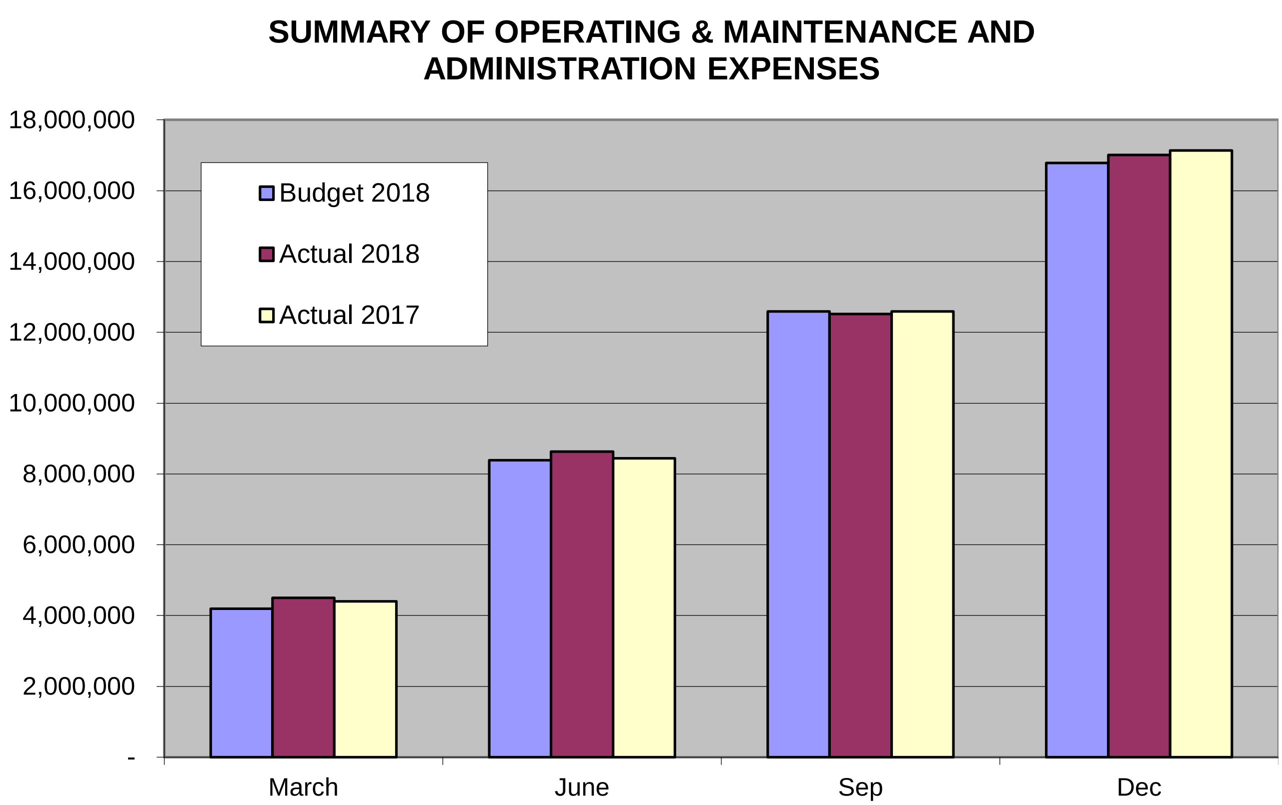
• OM&A Expenses on budget at Q3	On Target
• Distribution Revenue slightly below budget at Q3	Under Target
• Q3 CapEx expenditures ahead of plan	On Target
• Financial Ratios in acceptable range	On Target

FINAL QUARTER UPDATE

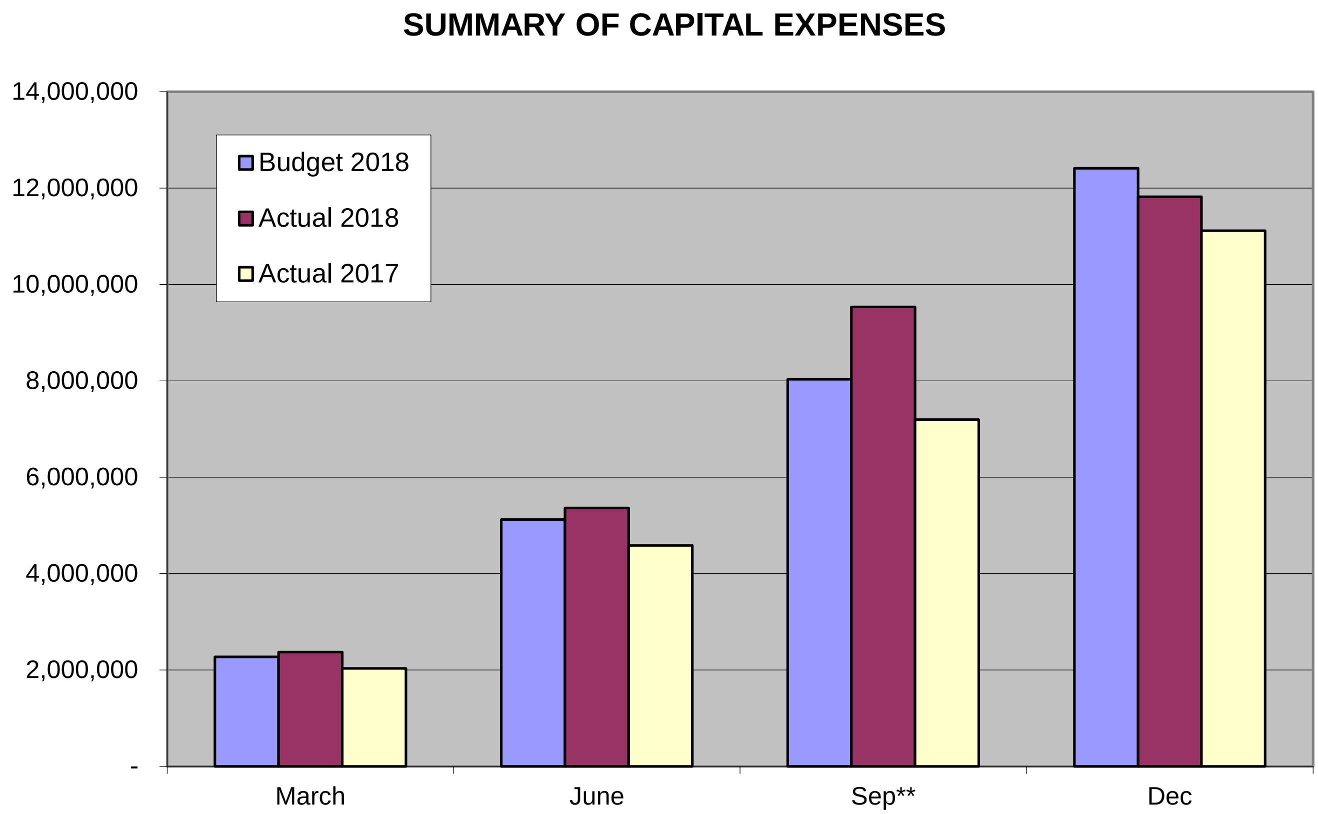
• OM&A Expenses (adjusted for merger costs) on budget at year end	On Target
• Distribution Revenue slightly below budget at year end	Under Target
• CapEx expenditures under budget – some carry over to 2018 (I.T.)	On Target
• Financial Ratios in acceptable range	On Target

Year To Date Summary Financial Results





Year To Date Summary Financial Results



Ratios as at December 31, 2018		Goal/ Requirement
Working Capital Ratio	1.54	>1.00:1
Quick Ratio	1.42	>1.00:1
Debt Capitalization Ratio	0.46	<0.60:1
Bank Debt Capitalization Ratio	0.25	
Debt Service Coverage - TD	2.65	>1.2:1

Thunder Bay Hydro Electricity Distribution Inc.
Board of Director's Corporate Evaluation Criteria

STRATEGIC OBJECTIVE – OPERATIONAL PERFORMANCE MEASURES

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Operational Performance Measures allow the Board to monitor the ongoing electricity reliability performance of the utility compared to historical performance. The Board can also monitor the ongoing operational performance of the utility as compared to Ontario Energy Board's Service Quality Indicator targets.

DESCRIPTION

- Monthly reliability indices as compared to previous years, available industry data and regulatory requirements
- Year to date Service Quality Indicators performance compared with targets established by the OEB

2018 OBJECTIVES	TARGET DATE(S)
• Reliability indices within the 5 year range of historical performance	Ongoing
• Service Quality Indicators meet/exceed OEB requirements	Ongoing
• Other internal measures as identified or developed in the future (i.e.: CDM program delivery, specific productivity factors, etc.)	Ongoing

FIRST QUARTER UPDATE

• Q1 Reliability Statistics compare well to historical	On Target
• All YTD OEB Service Indicator levels exceeded in Q1	On Target
• CDM programs in market – custom program in delivery	On Target
• Q1 CapEx projects on schedule	On Target

SECOND QUARTER UPDATE

• Q2 Reliability Statistics compare well to historical	On Target
• All YTD OEB Service Indicator levels exceeded at end of Q2	On Target
• CDM programs in market	On Target
• Q2 CapEx program on schedule	On Target

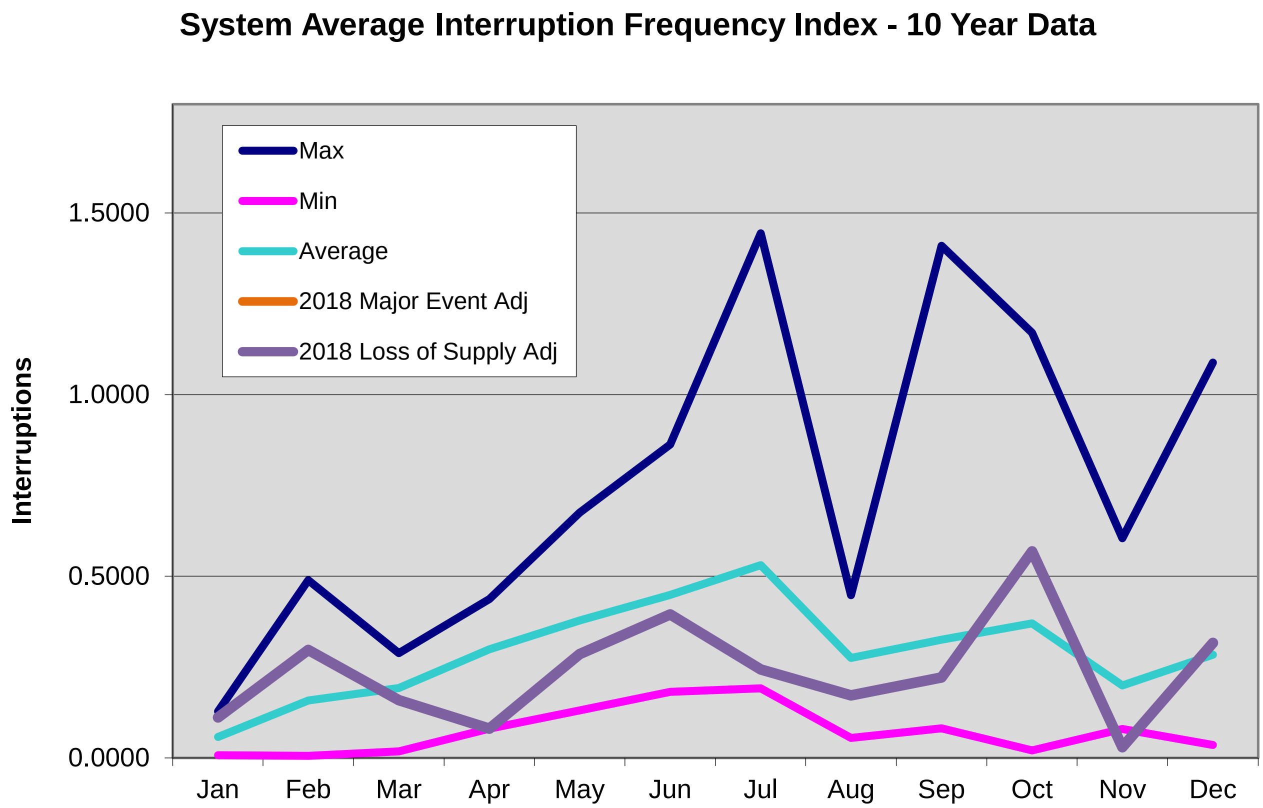
THIRD QUARTER UPDATE

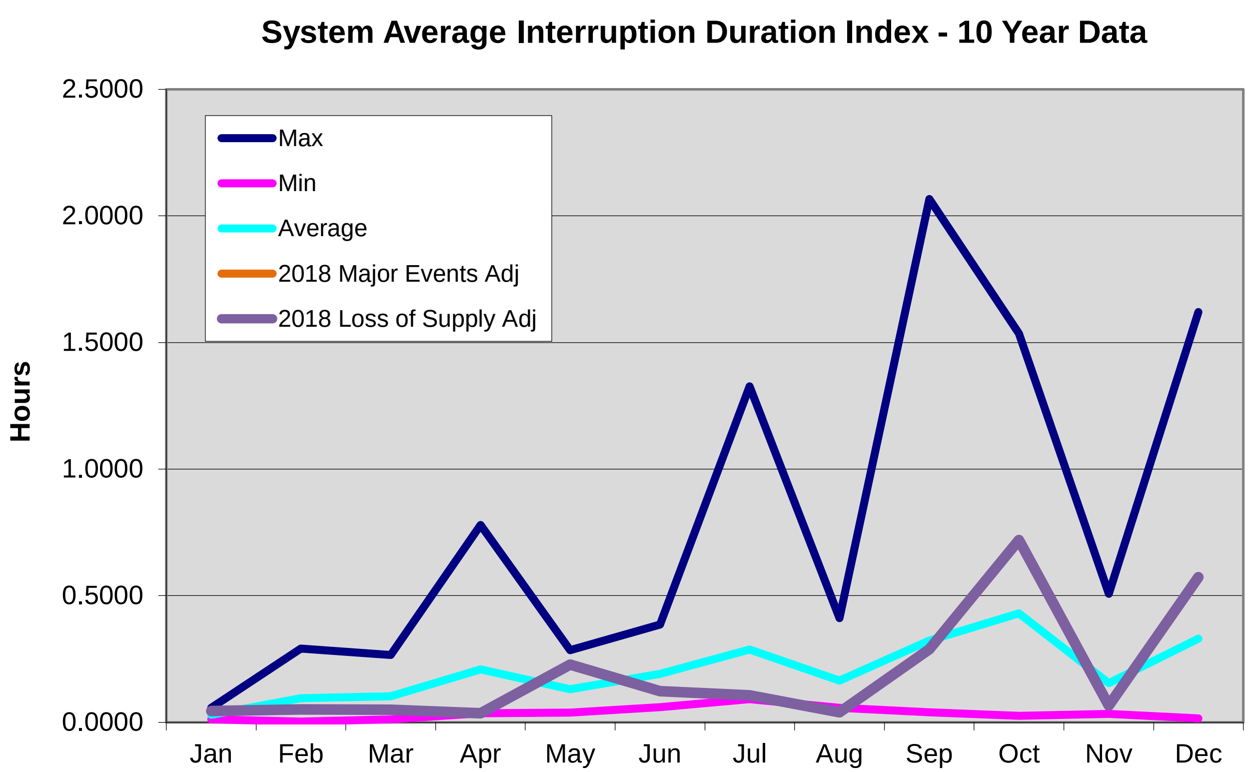
• Q3 Reliability Statistics compare well to historical	On Target
• All YTD OEB Service Indicator levels exceeded at end of Q3	On Target
• CDM programs in market	On Target
• Q3 CapEx program on schedule	On Target

FINAL QUARTER UPDATE

• Year End Reliability Statistics compare well to historical	On Target
• All YTD OEB Service Indicator levels exceeded at end of Q4	On Target
• CDM programs in market	On Target
• Q4 CapEx program completed on schedule	On Target

Year To Date Operational Performance Indices





Year To Date Operational Performance Indices

Customer Service Performance Indicators	Annual %	Standard %	Months Below Standard
New Service Connection-low voltage	100	90	0
New Service Connection-high voltage	100	90	0
Underground Cable Locates	92.5	90	1 – May 2018 = 76%
Telephone Accessibility	94.8	65	0
Appointments Met	100	90	0
Written Responses to inquiries	96.4	80	0
Emergency Response-Urban areas	91	80	1 – Sep 2018 = 54%
Emergency Response-Rural areas	90.5	80	1 – Oct 2018 = 60%

Synergy North Corporation
Board of Director's Corporate Evaluation Criteria

STRATEGIC OBJECTIVE – HEALTH & SAFETY

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2019 OBJECTIVES	TARGET DATE(S)
• Zero Lost Time Injuries (alternatively: Lost Time Incident and Severity result trends that compare favourably to comparative industry benchmarks)	Quarterly/Yearly
• Maintain positive performance trend for vehicle incidents, medical aid, dig-up, near miss incidents	Yearly
• Cultivate a culture where Safety is of primary importance	Ongoing
• Enhance External Health & Safety Programs through program delivery and community participation	Ongoing
• Enhance staff Health & Wellness Programs through program delivery	Ongoing

FIRST QUARTER UPDATE

• Zero Lost Time Incidents in Q1	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good	On Target
• Significant Health & Wellness and Safety training undertaken in Q1	On Target
• Limited scheduled external activity in Q1. Focus on internal training.	On Target

SECOND QUARTER UPDATE

• Zero Lost Time Incidents in Q2	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good	On Target
• Normal Health & Wellness and Safety training undertaken in Q2	On Target
• Increased scheduled external activity delivered in Q2.	On Target

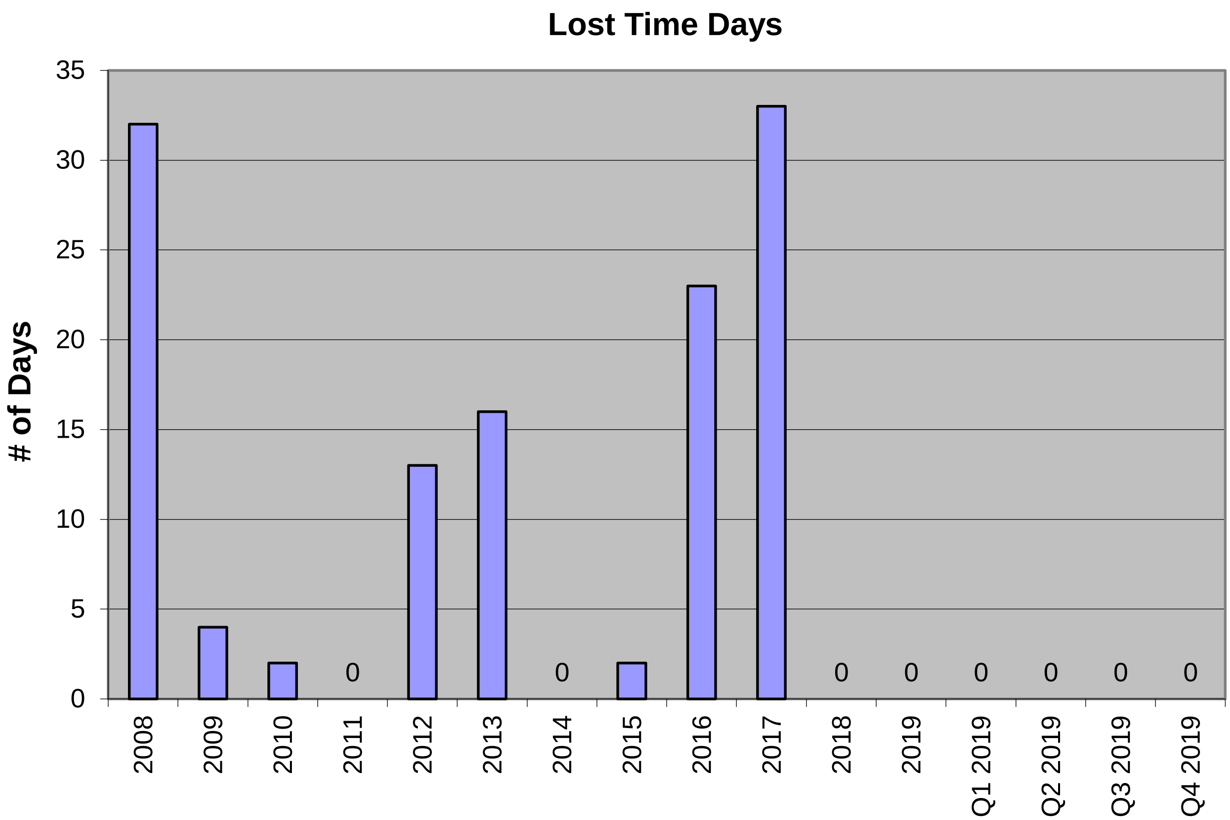
THIRD QUARTER UPDATE

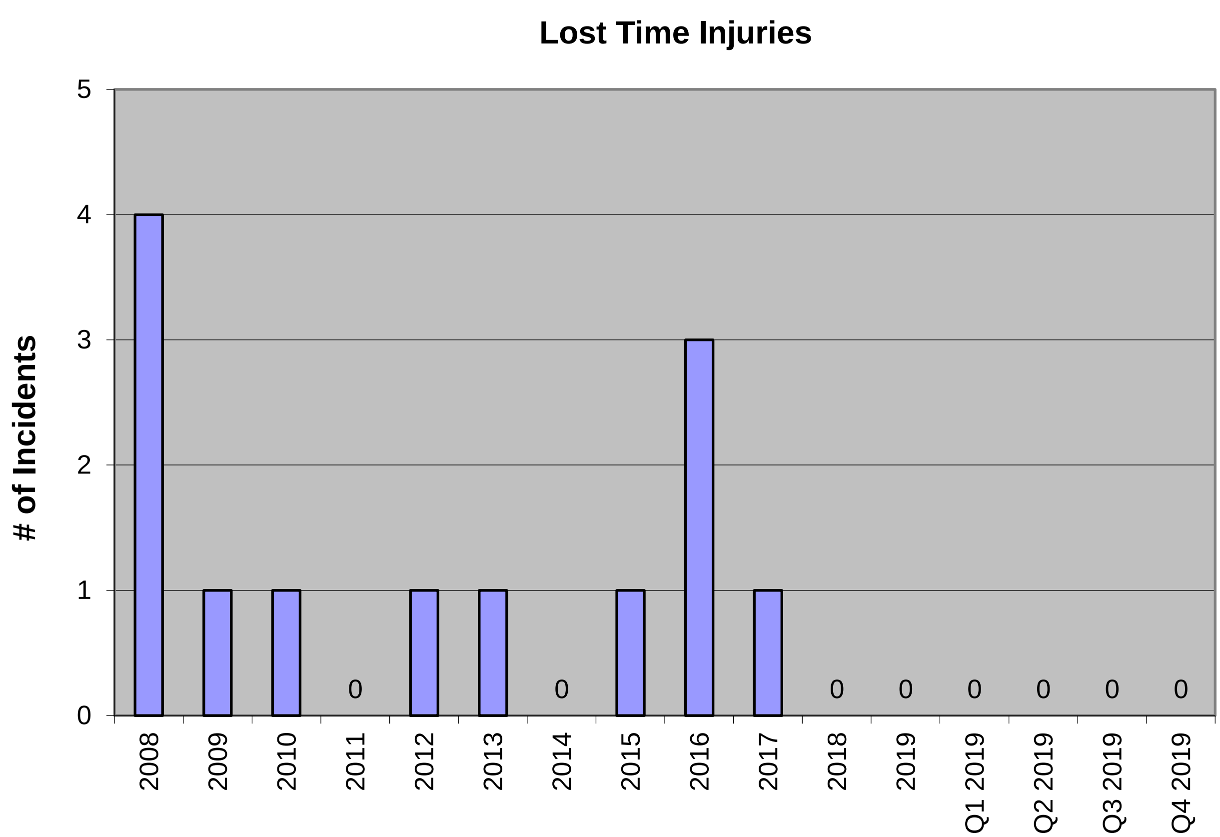
• Zero Lost Time Incidents in Q3	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good	On Target
• Reduced Health & Wellness and Safety training scheduled in Q3	On Target
• Reduced scheduled external activity delivered in Q3.	On Target

FINAL QUARTER UPDATE

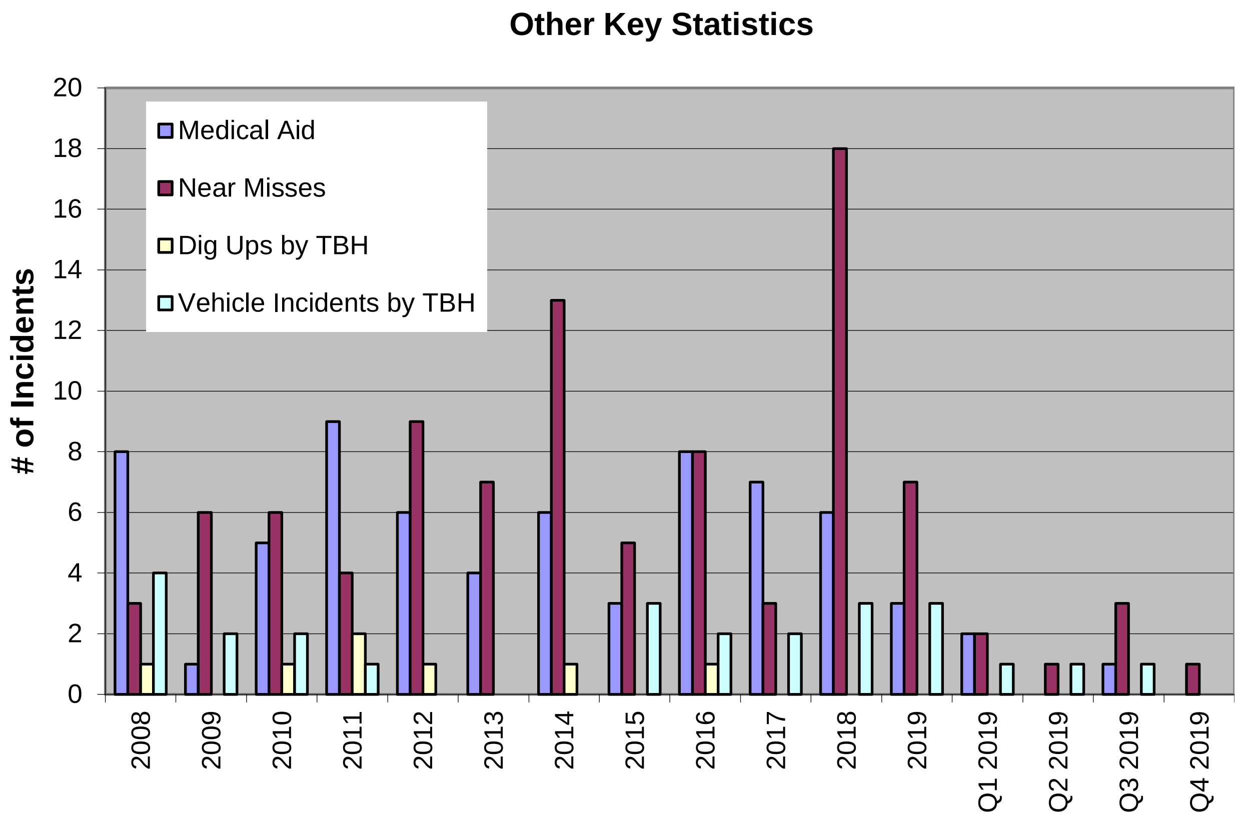
• Zero Lost Time Incidents in 2019	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good	On Target
• Scheduled Health & Wellness and Safety training completed in Q4	On Target
• Scheduled external activity delivered in Q4.	On Target

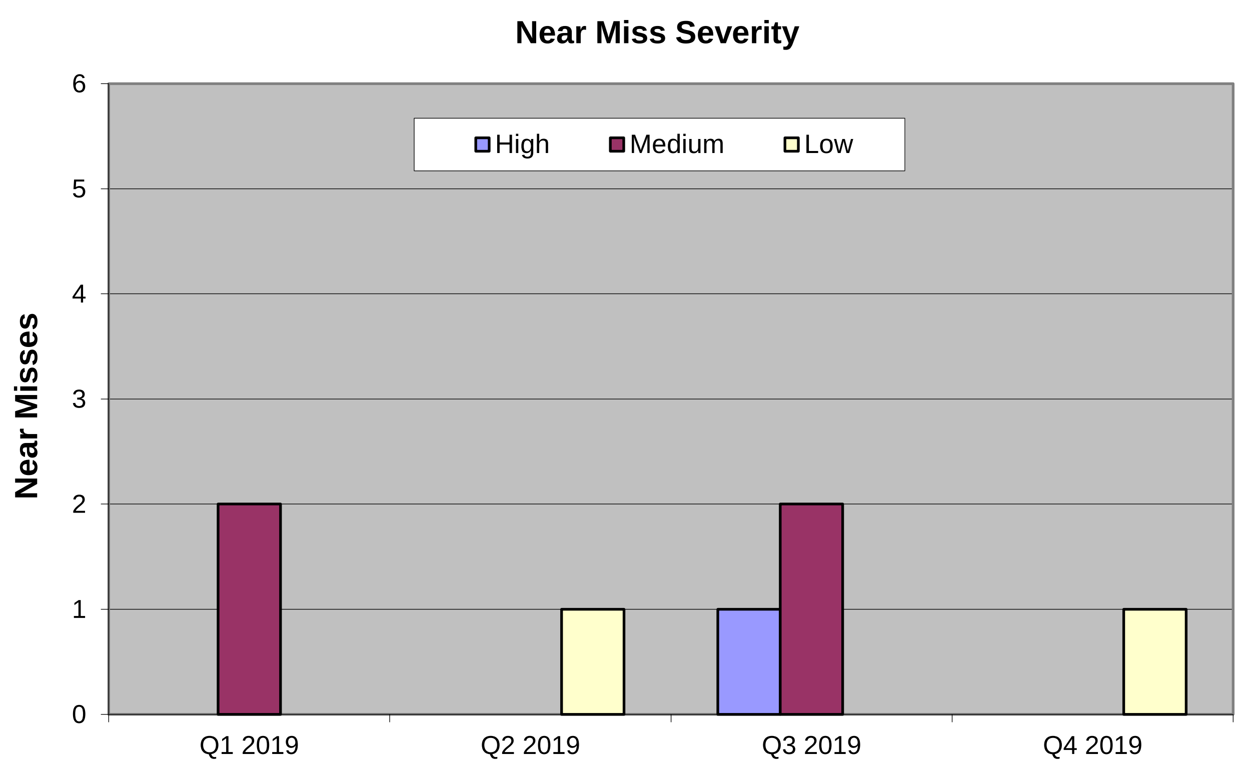
Historical Safety Statistics





Historical Safety Statistics





Synergy North Corporation
Board of Director's Corporate Evaluation Criteria

STRATEGIC OBJECTIVE – FINANCIAL PERFORMANCE MEASURES

Financial Performance Evaluation allows the Board to monitor the financial performance of the utility relative to budgeted and historical measures. Provides a high-level overview of the financial health of the organization and facilitates the exercise of the Board's financial due diligence.

DESCRIPTION

- Monthly O&M Expenditures compared to budget, previous year and available industry benchmarks
- Capital Expenditures compared to budget and previous year
- Distribution Revenue compared to budget and previous year
- Presentation of key financial ratios

2019 OBJECTIVES	TARGET DATE(S)
• Manage Controllable Expenses to 2019 Budget levels	Q4 2019
• Manage Capital Expenditures to 2019 Budget level	Q4 2019
• Maintain financial ratios above minimum threshold (Subject to change to reflect impact of specific strategic initiatives)	Ongoing

FIRST QUARTER UPDATE

• OM&A Expenses very slightly above budget at Q1	On Target
• Distribution Revenue slightly below budget at Q1	On Target
• Q1 CapEx expenditures slightly ahead of plan	On Target
• Financial Ratios in acceptable range	On Target

SECOND QUARTER UPDATE

• OM&A Expenses below budget at Q2	On Target
• Distribution Revenue slightly below budget at Q2	Below Target
• CapEx expenditures on target at end of Q2	On Target
• Financial Ratios in acceptable range	On Target

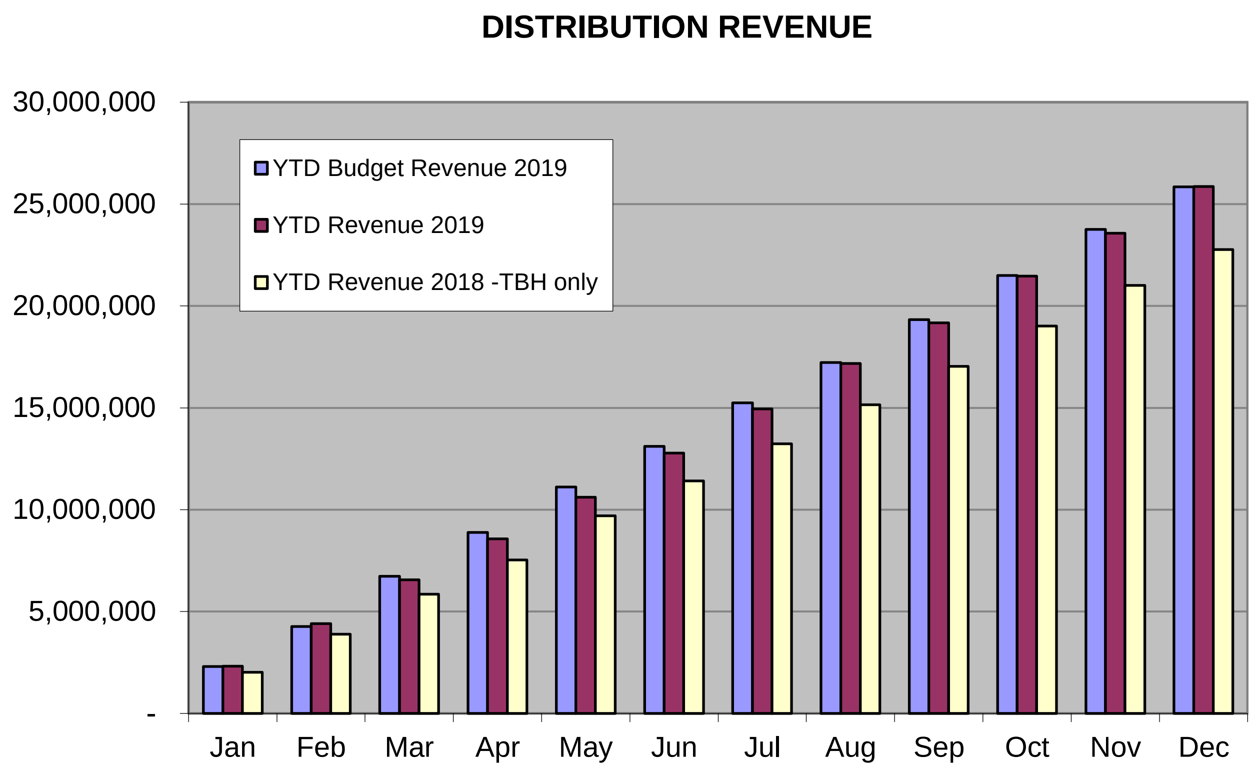
THIRD QUARTER UPDATE

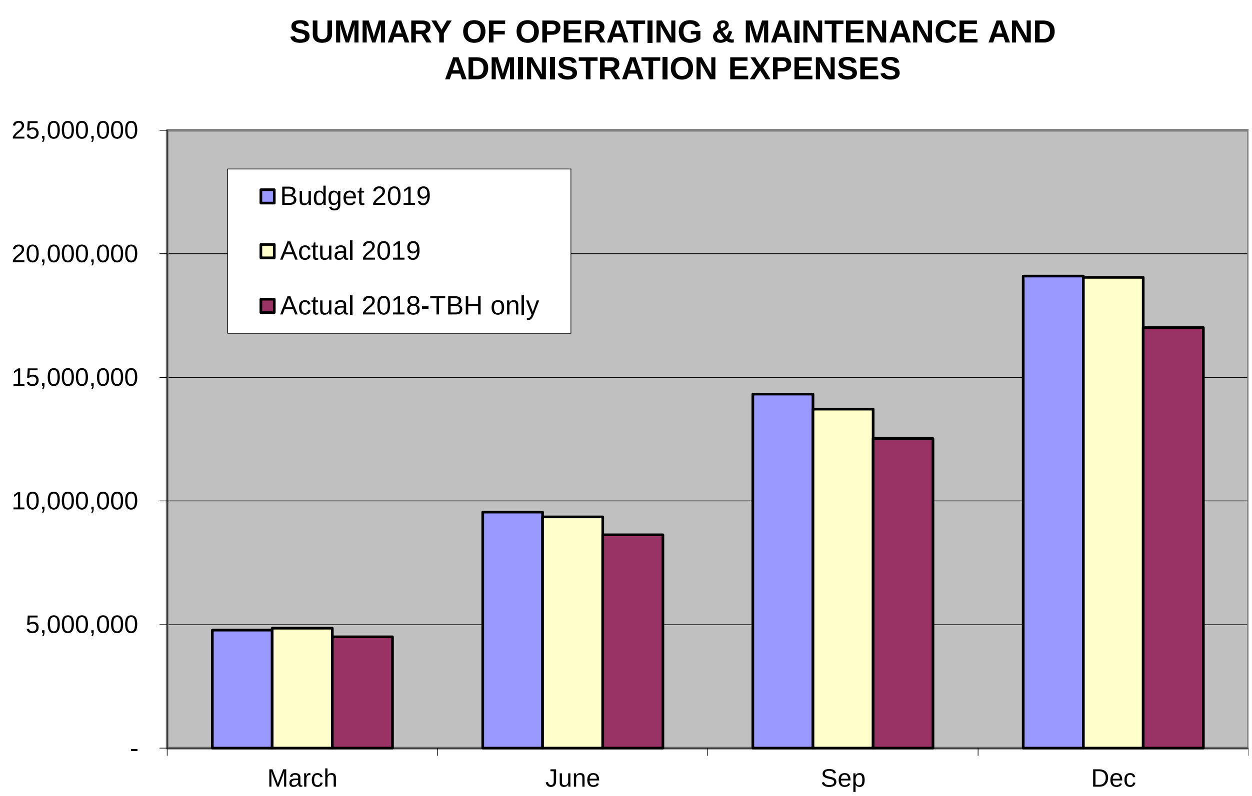
• OM&A Expenses below budget at Q3	On Target
• Distribution Revenue slightly below budget at Q3	On Target
• CapEx expenditures ahead of schedule at end of Q3	On Target
• Financial Ratios in acceptable range	On Target

FINAL QUARTER UPDATE

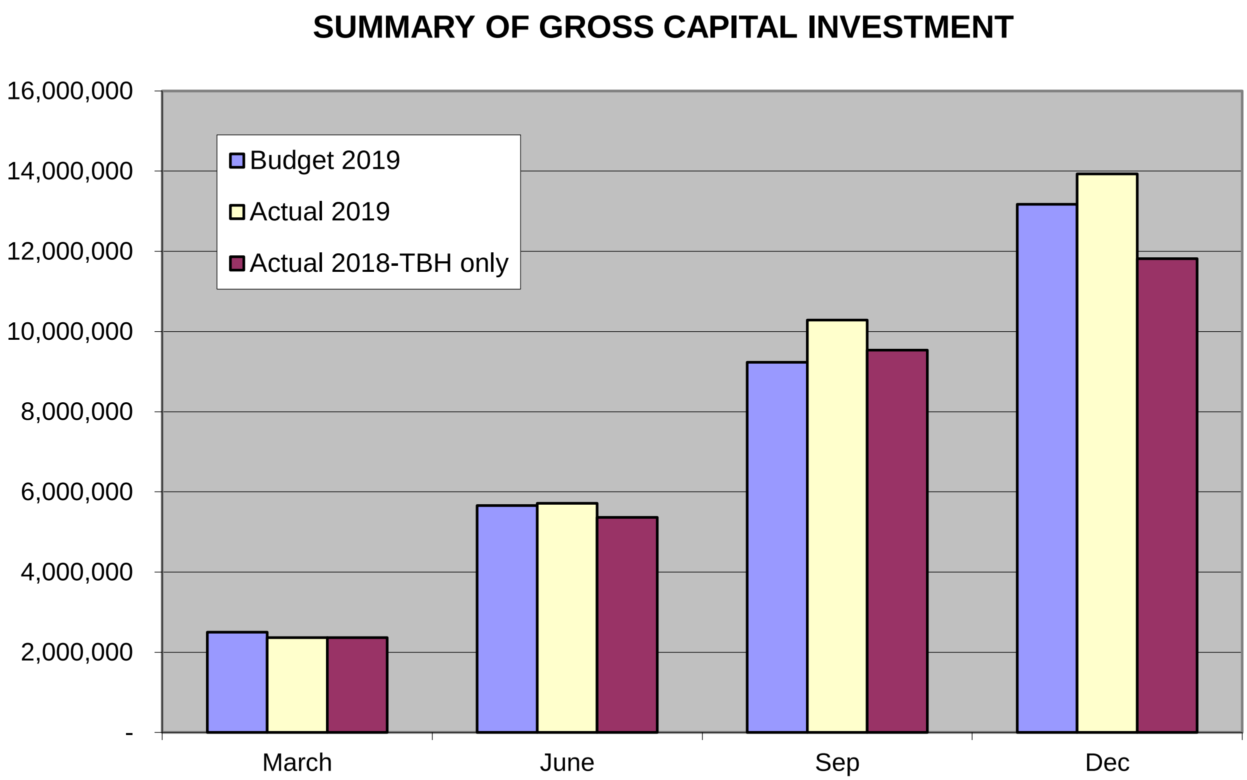
• OM&A Expenses below budget at year end	On Target
• Distribution Revenue very slightly below budget at year end	On Target
• CapEx projects on schedule and Net CapEx on budget at year end	On Target
• Financial Ratios in acceptable range	On Target

Year-To-Date Summary Financial Results





Year-To-Date Summary Financial Results



Ratios as at December 31, 2019		Goal/ Requirement
Working Capital Ratio	1.54	> 1.00:1
Quick Ratio	1.44	> 1.00:1
Debt Capitalization Ratio	0.45	< 0.60:1
Bank Debt Capitalization Ratio	0.28	
Debt Service Coverage - TD	2.02	> 1.2:1

Synergy North Corporation
Board of Director's Corporate Evaluation Criteria

STRATEGIC OBJECTIVE – OPERATIONAL PERFORMANCE MEASURES

One of Synergy North's Long-term Corporate Goals is to '**Provide a reliable supply of electricity to the residents and businesses of Thunder Bay'.**

Operational Performance Measures allow the Board to monitor the ongoing electricity reliability performance of the utility compared to historical performance. The Board can also monitor the ongoing operational performance of the utility as compared to Ontario Energy Board's Service Quality Indicator targets.

DESCRIPTION

- Monthly reliability indices as compared to previous years, available industry data and regulatory requirements
- Year to date Service Quality Indicators performance compared with targets established by the OEB

2019 OBJECTIVES	**TARGET DATE(S)**
• Reliability indices within the 5-year range of historical performance	Ongoing
• Service Quality Indicators meet/exceed OEB requirements	Ongoing
• Other internal measures as identified or developed in the future (i.e.: CDM program delivery, specific productivity factors, etc.)	Ongoing

FIRST QUARTER UPDATE

• Q1 Reliability Statistics compare well to historical	On Target
• All YTD OEB Service Indicator levels exceeded in Q1	On Target
• CDM programs in market – custom program in delivery	On Target
• Q1 CapEx projects on schedule	On Target

SECOND QUARTER UPDATE

• Q2 Reliability Statistics compare well to historical	On Target
• All YTD OEB Service Indicator levels exceeded in Q2	On Target
• Reduced CDM programs in market – custom program in delivery	On Target
• CapEx projects on schedule at end of Q2	On Target

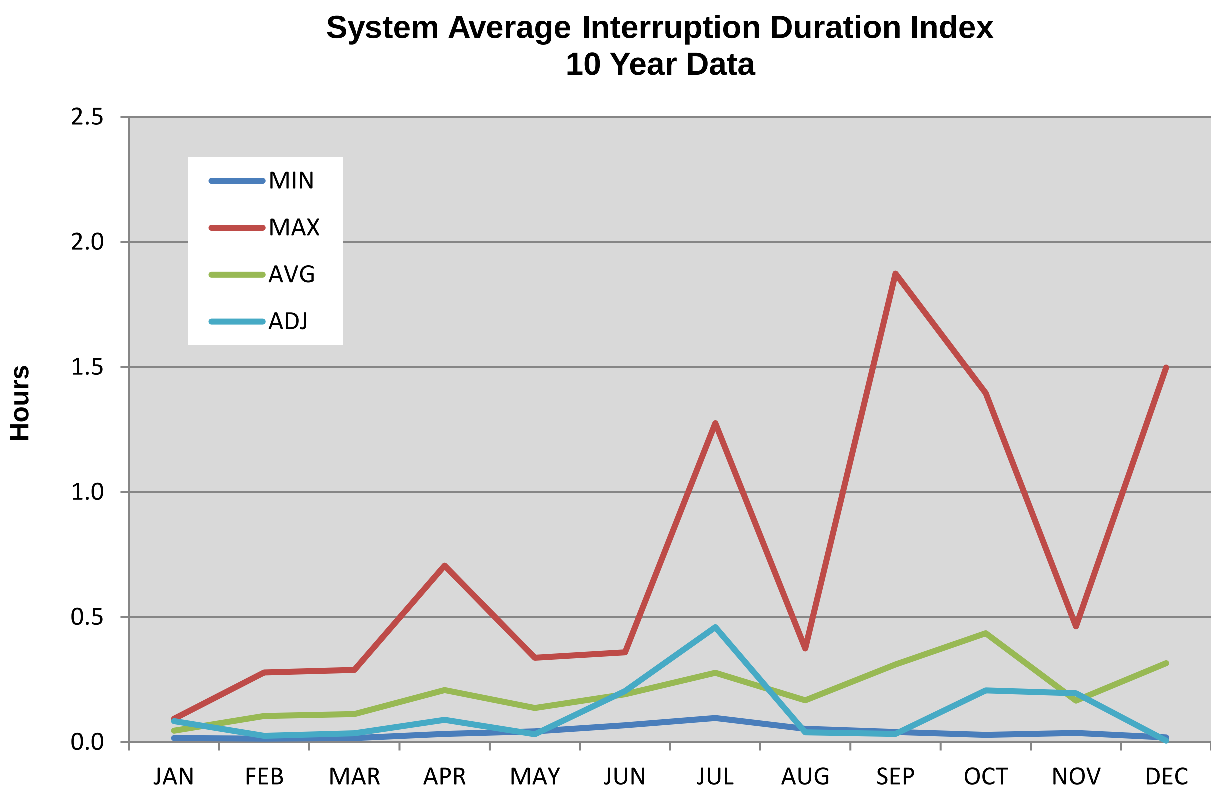
THIRD QUARTER UPDATE

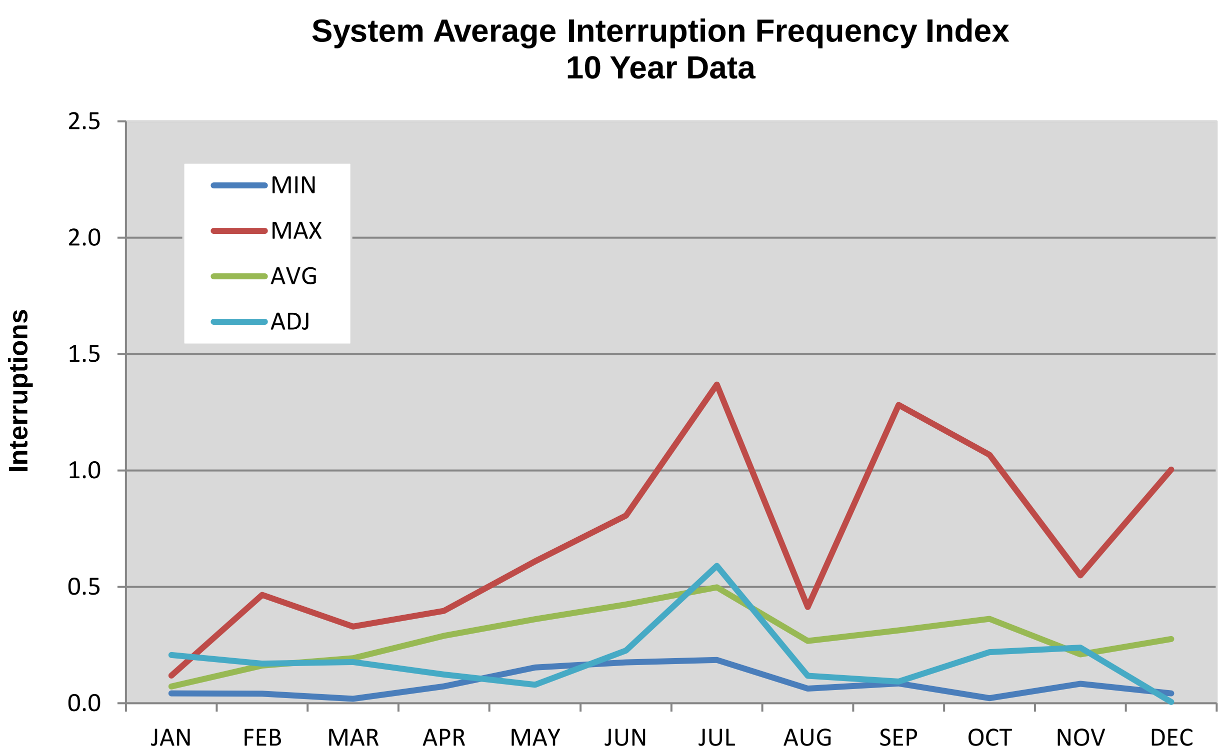
• Q3 Reliability Statistics compare well to historical	On Target
• All YTD OEB Service Indicator levels exceeded in Q3	On Target
• Reduced CDM programs in market – reporting to cease	On Target
• CapEx projects on schedule at end of Q3	On Target

FINAL QUARTER UPDATE

• 2019 Reliability Statistics compare well to historical - better than 10yr average	On Target
• All 2019 OEB Service Indicator levels exceeded	On Target
• Reduced CDM programs in market – reporting to cease	On Target
• CapEx projects on schedule at end of 2019	On Target

Year-To-Date Operational Performance Indices





Year-To-Date Operational Performance Indices

Customer Service Performance Indicators	Annual %	Standard %	Months Below Standard
New Service Connection-low voltage	100	90	0
New Service Connection-high voltage	100	90	0
Underground Cable Locates	99	90	0
Telephone Accessibility	91	65	0
Appointments Met	100	90	0
Written Responses to inquiries	99	80	0
Emergency Response-Urban areas	100	80	0
Emergency Response-Rural areas	100	80	0

Synergy North Corporation
Board of Director's Corporate Evaluation Criteria

STRATEGIC OBJECTIVE – HEALTH & SAFETY

Synergy North's primary Long-Term Corporate Goal is to '**Ensure that the Health and Safety of our Employees and the Public is the Utility's first priority'.**

As a utility, we will strive to prevent all incidents that might result in loss through personal injury, occupational illness or damage to property by continuously improving our Corporate Occupational Health & Safety (OHS) system.

DESCRIPTION

Senior Management is committed to safety excellence and will drive the agenda by establishing and maintaining a vision that outlines an ongoing and improving state of safe operation. All line managers will be personally involved with safety improvement objectives and performance audits. Continual efforts will be made to ensure a Culture of Safety permeates the organization.

2020 OBJECTIVES	TARGET DATE(S)
• Zero Lost Time Injuries (alternatively: Lost Time Incident and Severity result trends that compare favourably to comparative industry benchmarks)	Quarterly/Yearly
• Maintain positive performance trend for vehicle incidents, medical aid, dig-up, near miss incidents	Yearly
• Cultivate a culture where Safety is of primary importance	Ongoing
• Enhance External Health & Safety Programs through program delivery and community participation	Ongoing
• Enhance staff Health & Wellness Programs through program delivery	Ongoing

FIRST QUARTER UPDATE

• Zero Lost Time Incidents in Q1	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good	On Target
• Truncated Health & Wellness and Safety training schedule in Q1 – COVID-19 – focus	
• on required training	Below Target
• Limited scheduled external activity in Q1. Focus on internal training.	On Target

SECOND QUARTER UPDATE

• Zero Lost Time Incidents in Q2	On Target
• Adjusted JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good	On Target
• Truncated Health & Wellness and Safety training schedule in Q2 – COVID-19 – focus	
• on required training	Below Target
• Limited scheduled external activity in Q2. Focus on internal training.	On Target

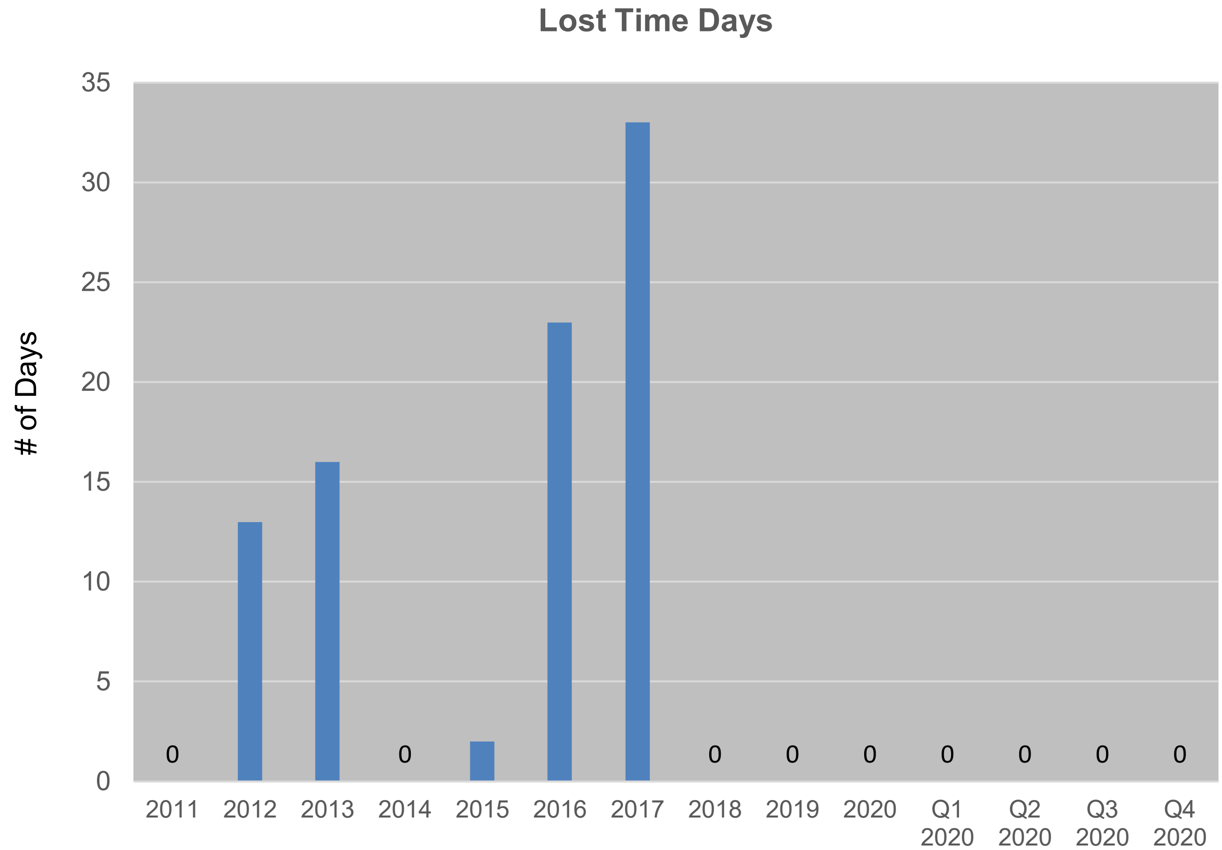
THIRD QUARTER UPDATE

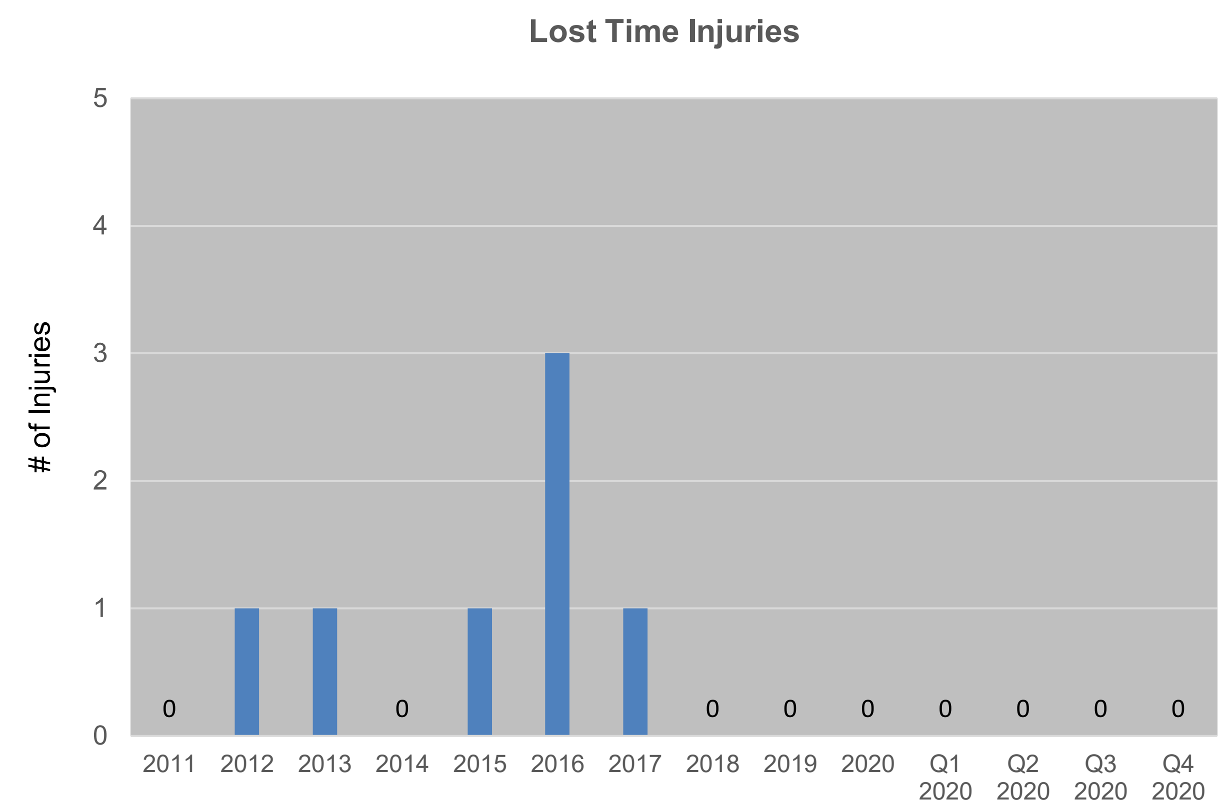
• Zero Lost Time Incidents in Q3	On Target
• Adjusted JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats excellent	On Target
• Truncated Health & Wellness and Safety training schedule in Q3 – COVID-19 – focus	
• on required training	Below Target
• Low scheduled external activity in Q3. Focus on internal training.	On Target

FINAL QUARTER UPDATE

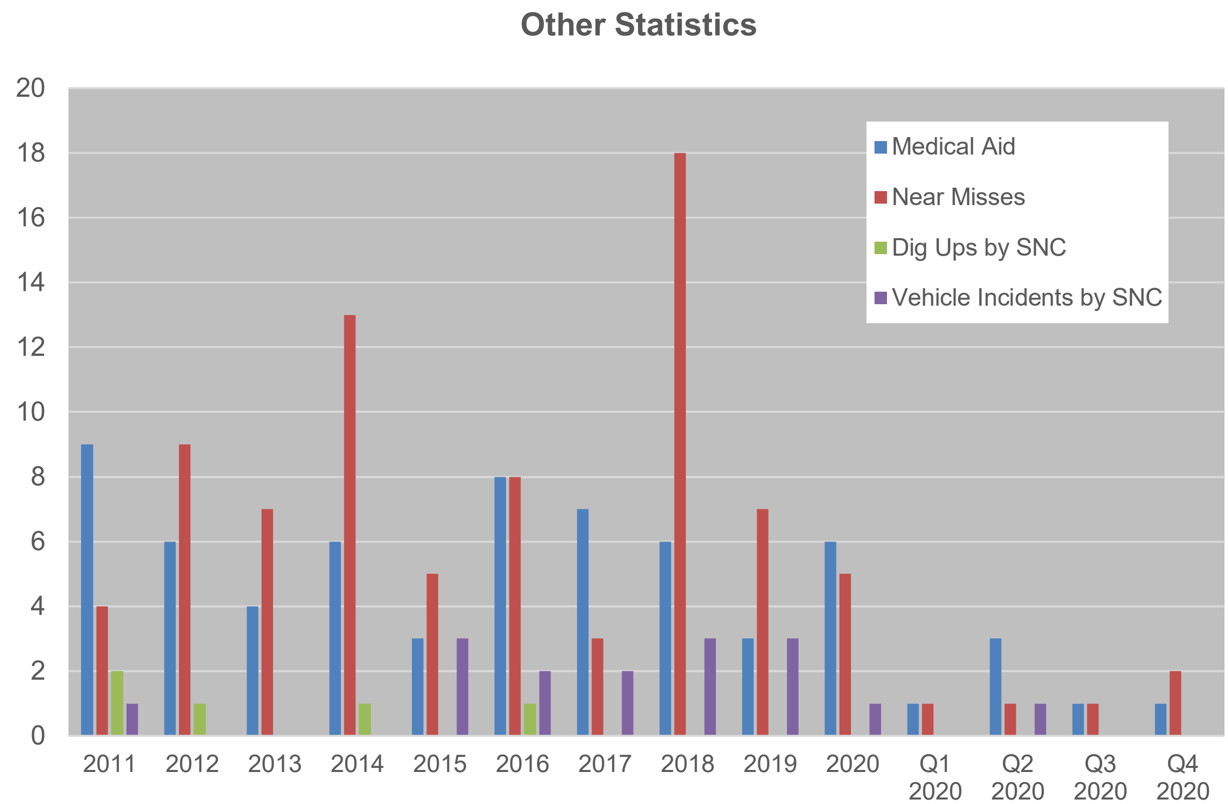
• Zero Lost Time Incidents in Q4	On Target
• Adjusted JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats excellent	On Target
• Virtual/Adjusted Health & Wellness and Safety training schedule in Q4 – COVID-19	Below Target
• Low scheduled external activity in Q4.	On Target

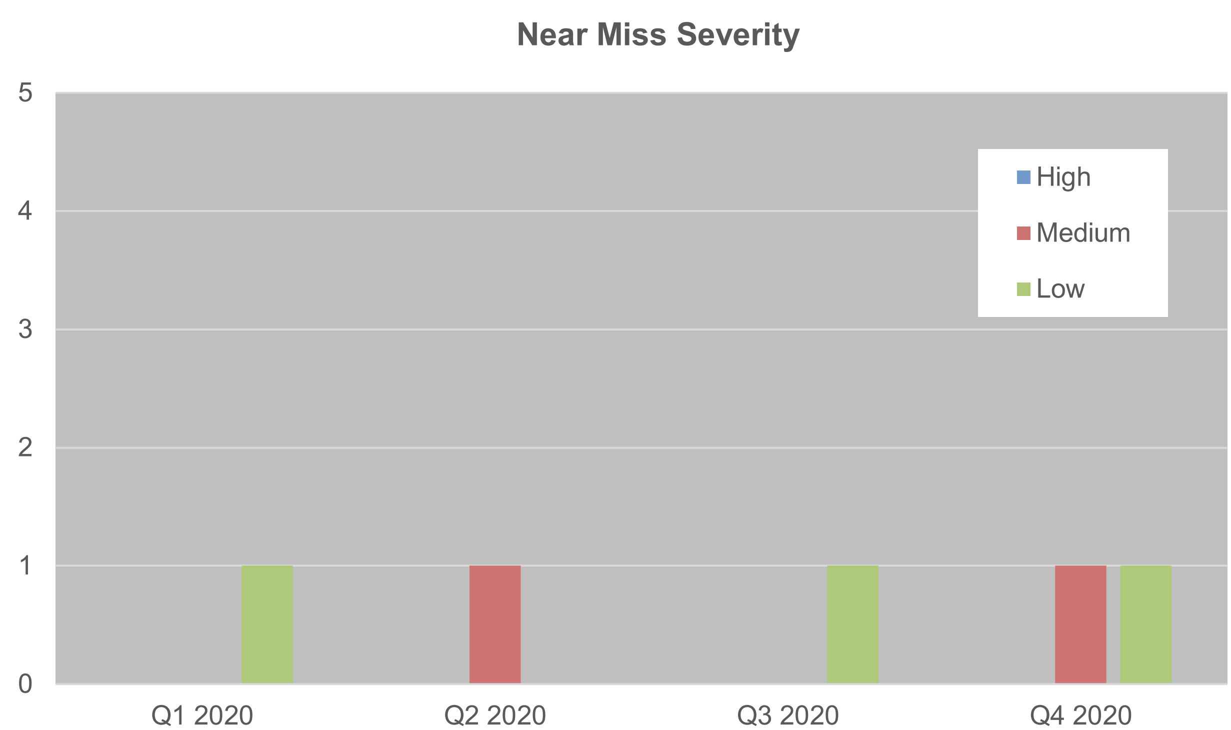
Historical Safety Statistics





Historical Safety Statistics





Synergy North Corporation
Board of Director's Corporate Evaluation Criteria

STRATEGIC OBJECTIVE – FINANCIAL PERFORMANCE MEASURES

Financial Performance Evaluation allows the Board to monitor the financial performance of the utility relative to budgeted and historical measures. Provides a high-level overview of the financial health of the organization and facilitates the exercise of the Board's financial due diligence.

DESCRIPTION

- Monthly O&M Expenditures compared to budget, previous year and available industry benchmarks
- Capital Expenditures compared to budget and previous year
- Distribution Revenue compared to budget and previous year
- Presentation of key financial ratios

2020 OBJECTIVES	TARGET DATE(S)
• Manage Controllable Expenses to 2019 Budget levels	Q4 2019
• Manage Capital Expenditures to 2019 Budget level	Q4 2019
• Maintain financial ratios above minimum threshold (Subject to change to reflect impact of specific strategic initiatives)	Ongoing

FIRST QUARTER UPDATE

• OM&A Expenses below budget at Q1	On Target
• Distribution Revenue below budget at Q1	Below Target
• Q1 CapEx expenditures behind plan – COVID-19	Below Target
• Financial Ratios in acceptable range	On Target

SECOND QUARTER UPDATE

• OM&A Expenses below budget at Q2	On Target
• Distribution Revenue below budget at Q2 – COVID Impact	Below Target
• CapEx expenditures continue to be deferred – COVID-19	Below Target
• Financial Ratios in acceptable range	On Target

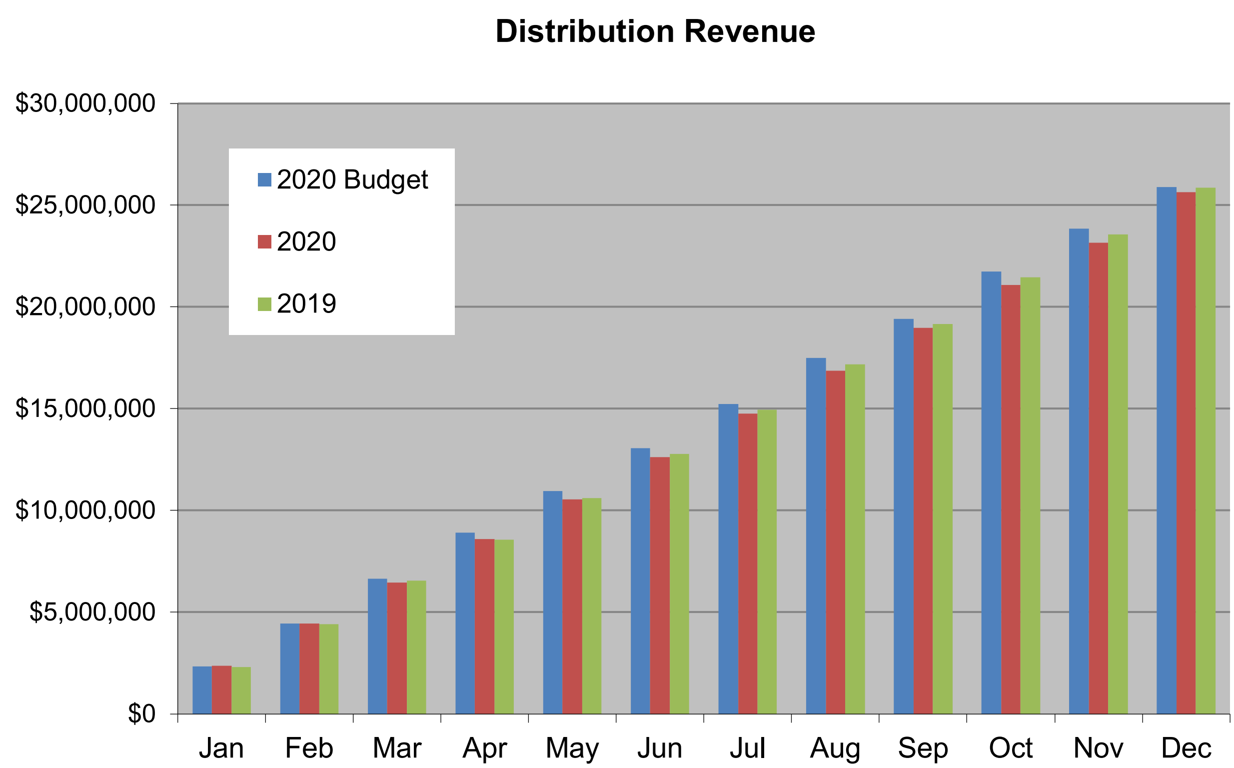
THIRD QUARTER UPDATE

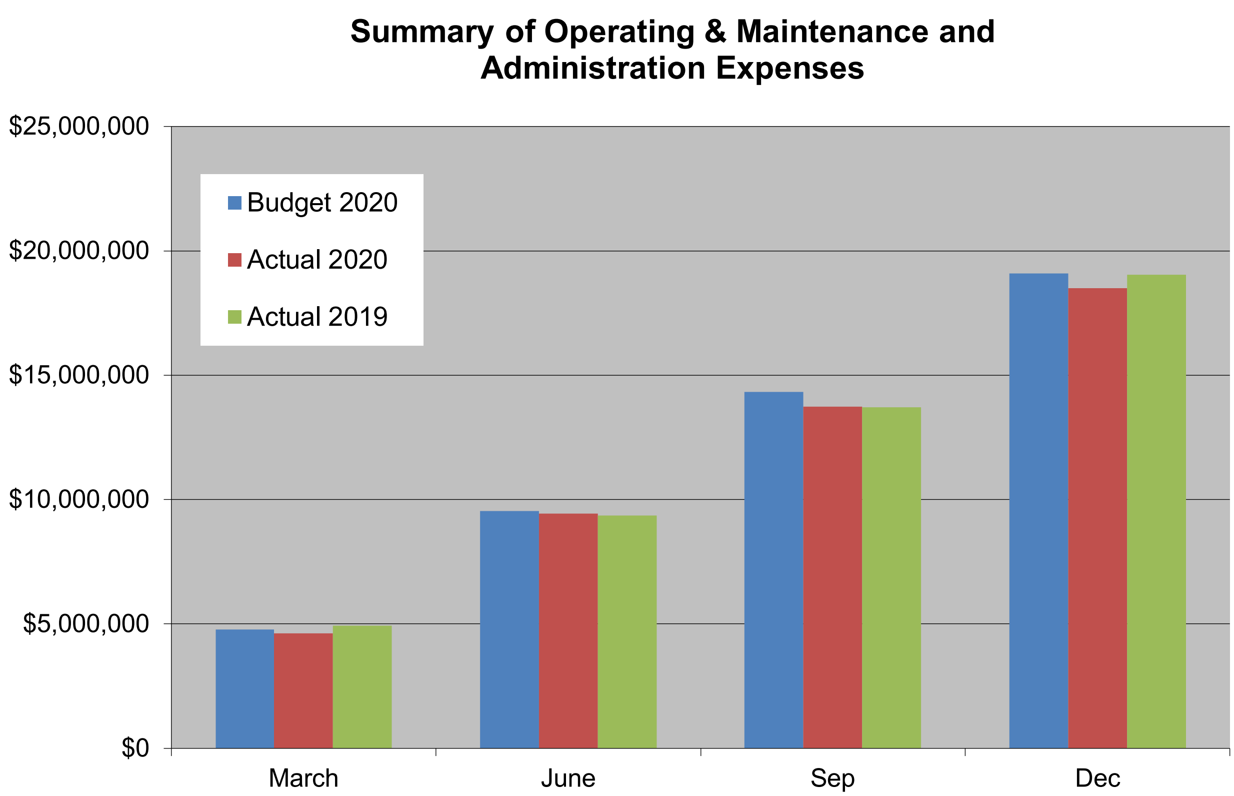
• OM&A Expenses below budget at Q3	On Target
• Distribution Revenue below budget at Q3 – COVID Impact	Below Target
• CapEx expenditures continue to be deferred – COVID-19	Below Target
• Financial Ratios in acceptable range	On Target

FINAL QUARTER UPDATE

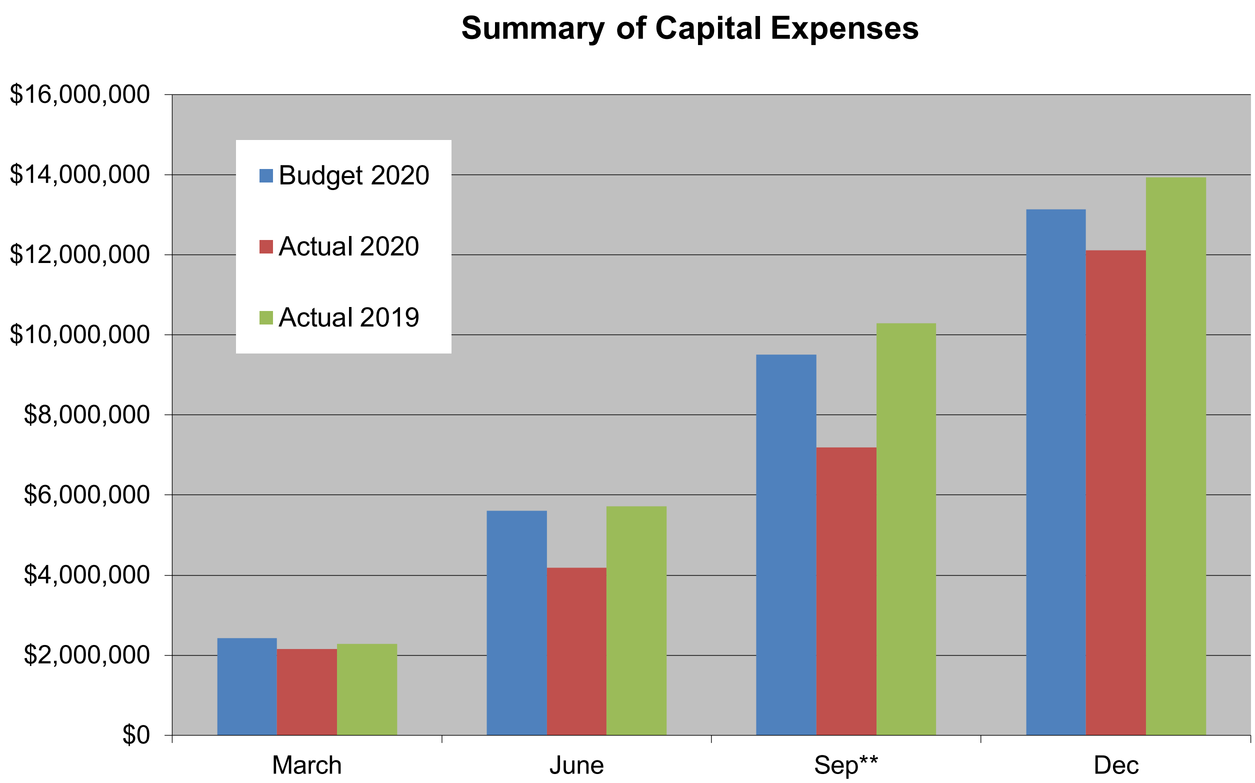
• OM&A Expenses below budget at Q4	On Target
• Distribution Revenue below budget at Q4 – COVID Impact	Below Target
• CapEx expenditures continue to be deferred – COVID-19	Below Target
• Financial Ratios in acceptable range	On Target

Year To Date Summary Financial Results





Year To Date Summary Financial Results



**Note that the above budget by quarter calculation for capital is based on the actual quarter expenditures in the prior year.

Ratios as at December 30, 2020		Goal/ Requirement
Working Capital Ratio	1.97	> 1.00:1
Quick Ratio	1.81	> 1.00:1
Debt Capitalization Ratio	0.45	< 0.60:1
Bank Debt Capitalization Ratio	0.30	
Debt Service Coverage - TD	2.49	> 1.2:1

Synergy North Corporation
Board of Director's Corporate Evaluation Criteria

STRATEGIC OBJECTIVE – OPERATIONAL PERFORMANCE MEASURES

One of Synergy North's Long-term Corporate Goals is to '**Provide a reliable supply of electricity to the residents and businesses of Thunder Bay'.**

Operational Performance Measures allow the Board to monitor the ongoing electricity reliability performance of the utility compared to historical performance. The Board can also monitor the ongoing operational performance of the utility as compared to Ontario Energy Board's Service Quality Indicator targets.

DESCRIPTION

- Monthly reliability indices as compared to previous years, available industry data and regulatory requirements.
- Year to date Service Quality Indicators performance compared with targets established by the OEB.

2020 OBJECTIVES	TARGET DATE(S)
• Reliability indices within the 5-year range of historical performance	Ongoing
• Service Quality Indicators meet/exceed OEB requirements	Ongoing
• Other internal measures as identified or developed in the future (i.e.: CDM program delivery, specific productivity factors, etc.)	Ongoing

FIRST QUARTER UPDATE

• Q1 Reliability Statistics excellent compared to historical	On Target
• All YTD OEB Service Indicator levels exceeded in Q1	On Target
• Q1 CapEx projects behind schedule – COVID-19	Below Target

SECOND QUARTER UPDATE

• Q2 Reliability Statistics remain excellent compared to historical	On Target
• All YTD OEB Service Indicator levels exceeded in Q2 except located – Rescheduling due to Covid response	On Target
• Q2 CapEx projects behind original plan – COVID-19	Below Target

THIRD QUARTER UPDATE

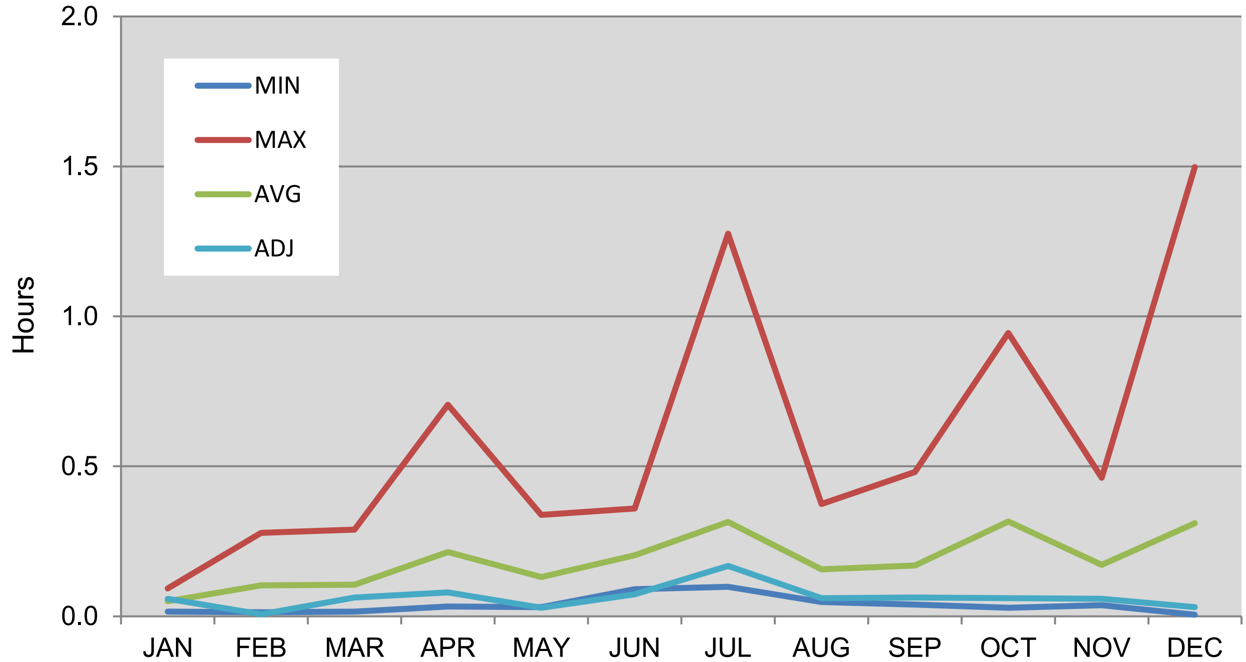
• Q3 Reliability Statistics remain excellent compared to historical	On Target
• All YTD OEB Service Indicator levels exceeded in Q3 except locates – rescheduling and contractor capacity issue due to pandemic	On Target
• Some CapEx projects deferred – COVID-19	Below Target

FINAL QUARTER UPDATE

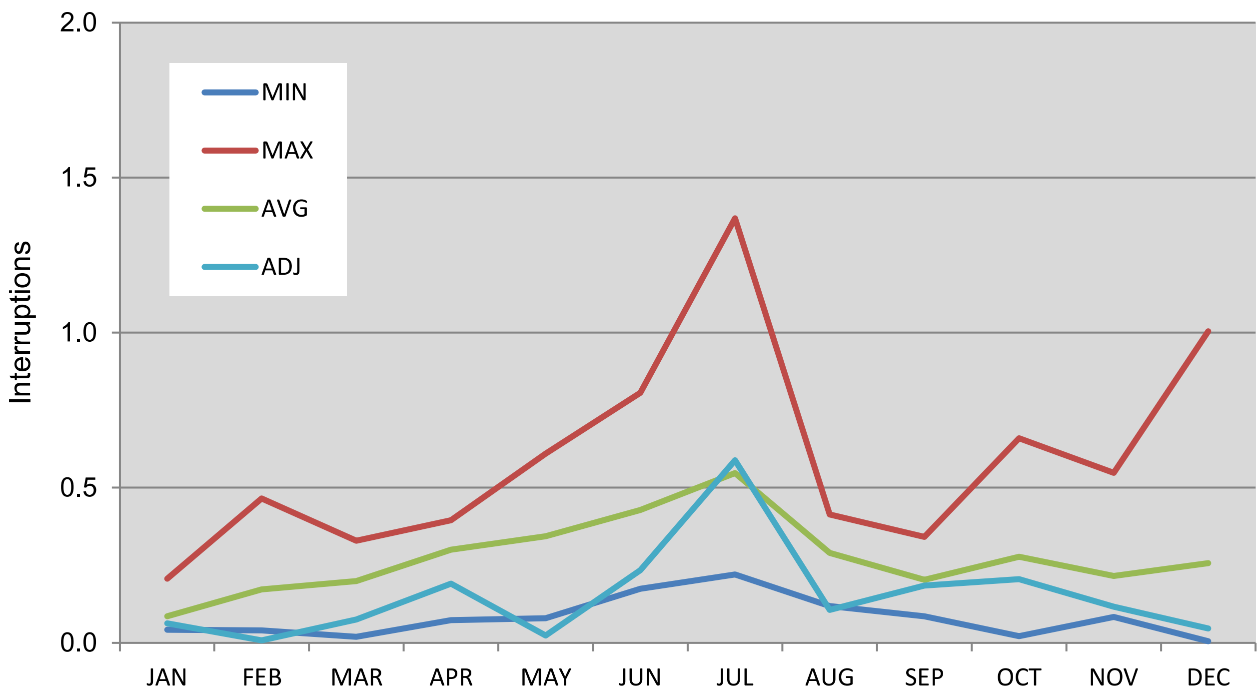
• Q4 Reliability Statistics remain excellent compared to historical	On Target
• All YTD OEB Service Indicator levels exceeded to year-end except locates – rescheduling and contractor capacity issue due to pandemic	On Target
• Some CapEx projects deferred – COVID-19	Below Target

Year To Date Operational Performance Indices

SAIDI - System Average Interruption Duration Index
Monthly Comparison - 10 Yr Data



SAIFI - System Average Interruption Frequency Index
Monthly Comparison - 10 Yr Data



Year To Date Operational Performance Indices

Customer Service Performance Indicators	Annual %	Standard %	Months Below Standard
New Service Connection-low voltage	100	90	0
New Service Connection-high voltage	92.31	90	1
Underground Cable Locates	88.05	90	3
Telephone Accessibility	87.5	65	0
Appointments Met	100	90	0
Written Responses to inquiries	97	80	0
Emergency Response-Urban areas	98.8	80	0
Emergency Response-Rural areas	100	80	0

Synergy North Corporation
Board of Director's Corporate Evaluation Criteria

PEOPLE OBJECTIVES – HEALTH & SAFETY STRATEGY

Corporate Goal: Promote, work and live safety achieving positive health and safety outcomes for employees and the public.

As a utility, we will strive to prevent all incidents that might result in loss through personal injury, occupational illness or damage to property by continuously improving our Corporate Occupational Health & Safety (OHS) system.

DESCRIPTION

Senior Management is committed to safety excellence and will drive the agenda by establishing and maintaining a vision that outlines an ongoing and improving state of safe operation. All line managers will be personally involved with safety improvement objectives and performance audits. Continual efforts will be made to ensure a Culture of Safety permeates the organization.

2021 OBJECTIVES	TARGET DATE(S)
• Zero Lost Time Injuries (alternatively: Lost Time Incident and Severity result trends that compare favourably to comparative industry benchmarks)	Quarterly/Yearly
• Maintain positive performance trend for vehicle incidents, medical aid, dig-up, near miss incidents	Yearly
• Cultivate a culture where Safety is of primary importance	Ongoing
• Enhance External Health & Safety Programs through program delivery and community participation	Ongoing
• Enhance staff Health & Wellness Programs through program delivery	Ongoing

FIRST QUARTER UPDATE

• Zero Lost Time Incidents in Q1	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good	On Target
• Truncated Health & Wellness and Safety training schedule in Q1 – COVID-19 – focus on required training	Below Target
• Limited scheduled external activity in Q1. Focus on internal training.	On Target

SECOND QUARTER UPDATE

• Zero Lost Time Incidents in Q2	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good	On Target
• Limited scheduled external activity in Q2. Focus on internal training.	On Target
• Truncated Health & Wellness and Safety training schedule in Q2- COVID-19- focus on required training	Below Target

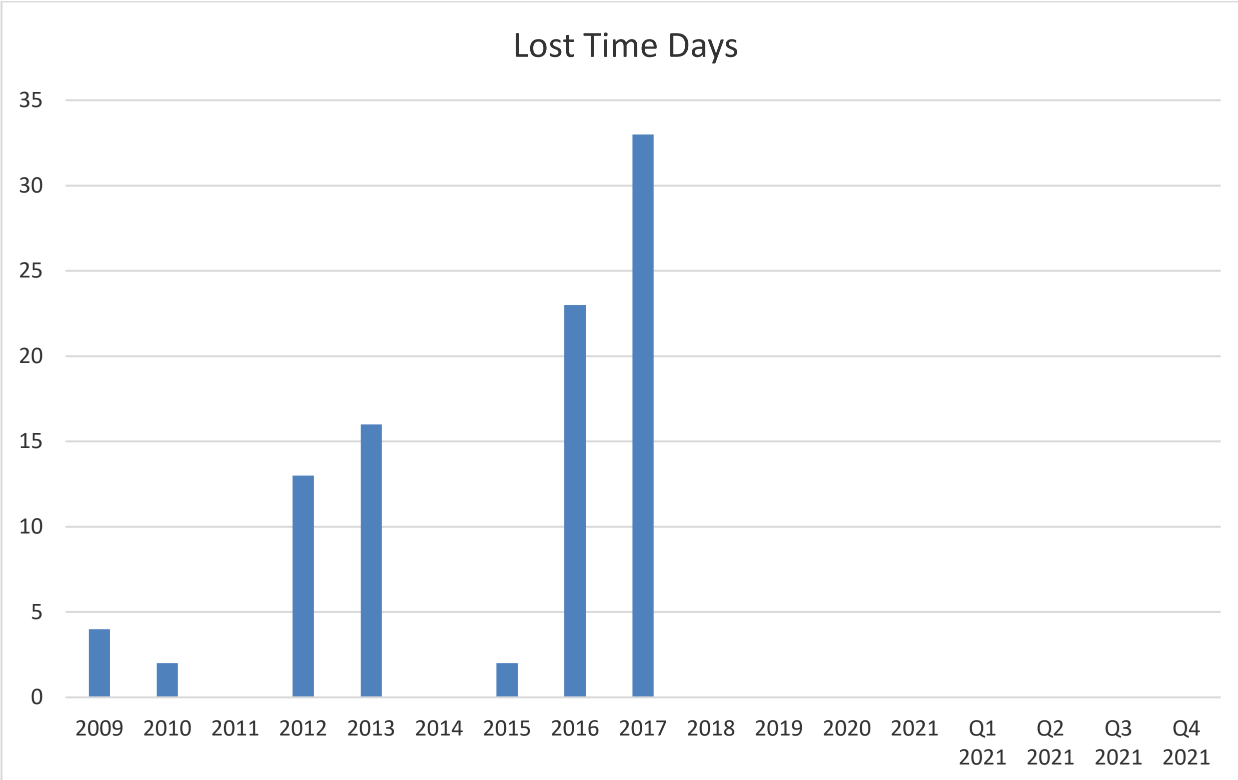
THIRD QUARTER UPDATE

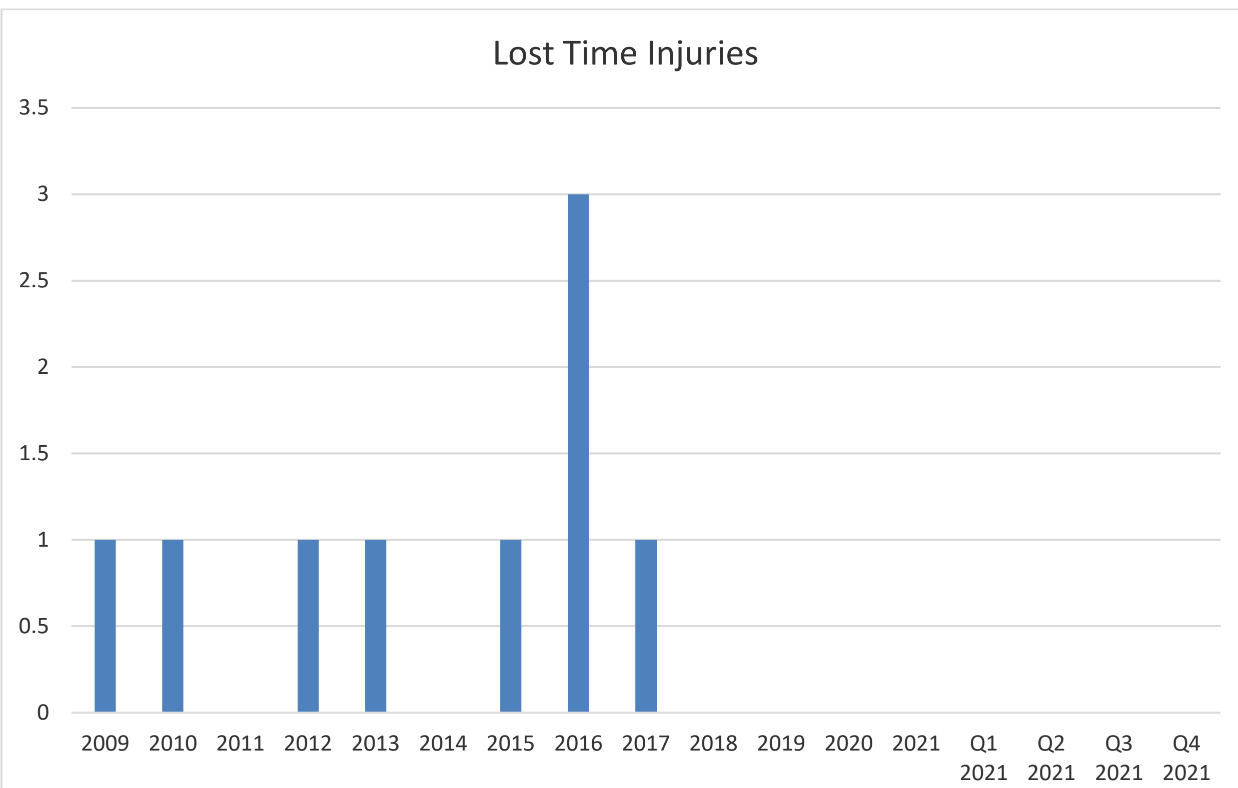
• Zero Lost Time Incidents in Q3	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good	On Target
• Limited scheduled external activity in Q3. Focus on internal training.	On Target
• Truncated Health & Wellness and Safety training schedule in Q3- COVID-19- focus on required training	Below Target

FINAL QUARTER UPDATE

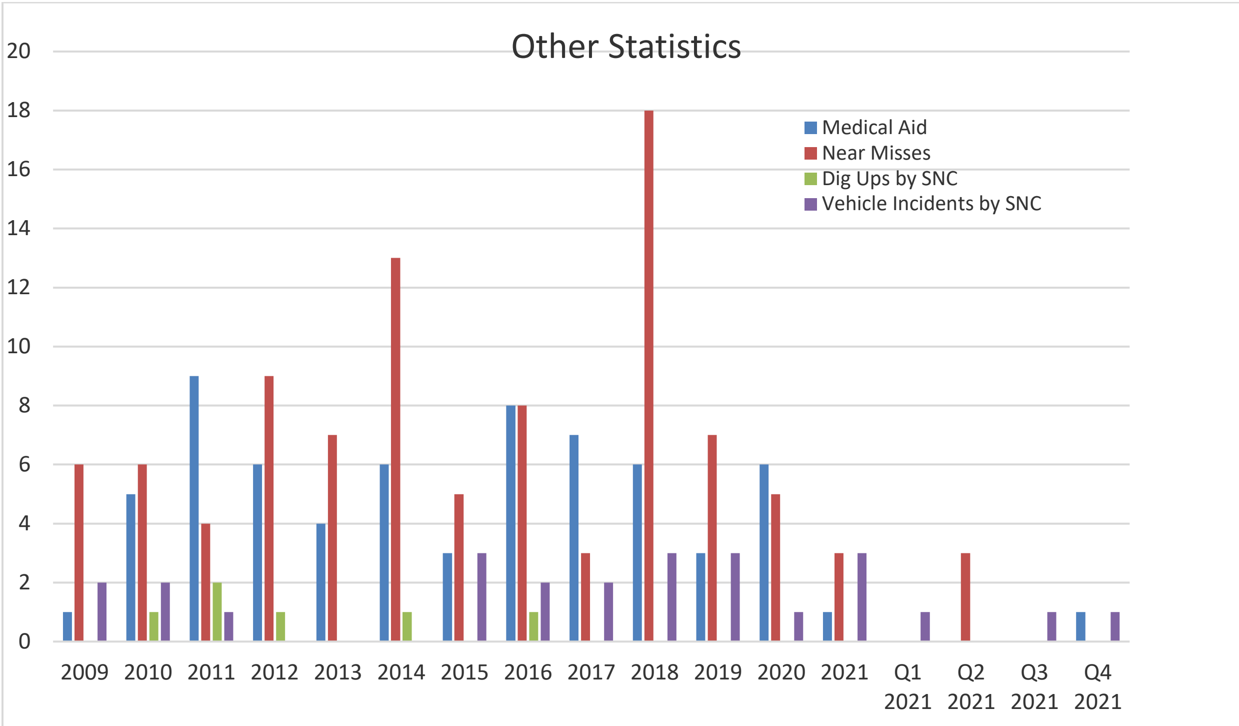
• Zero Lost Time Incidents in Q4	On Target
• Ongoing JHSC, Ergonomic, Accident Prevention meeting activity to support culture	On Target
• Other key stats good	On Target
• Limited scheduled external activity in Q4. Focus on internal training.	On Target
• Truncated Health & Wellness and Safety training schedule in Q4- COVID-19- all required training was completed in 2021.	Below Target

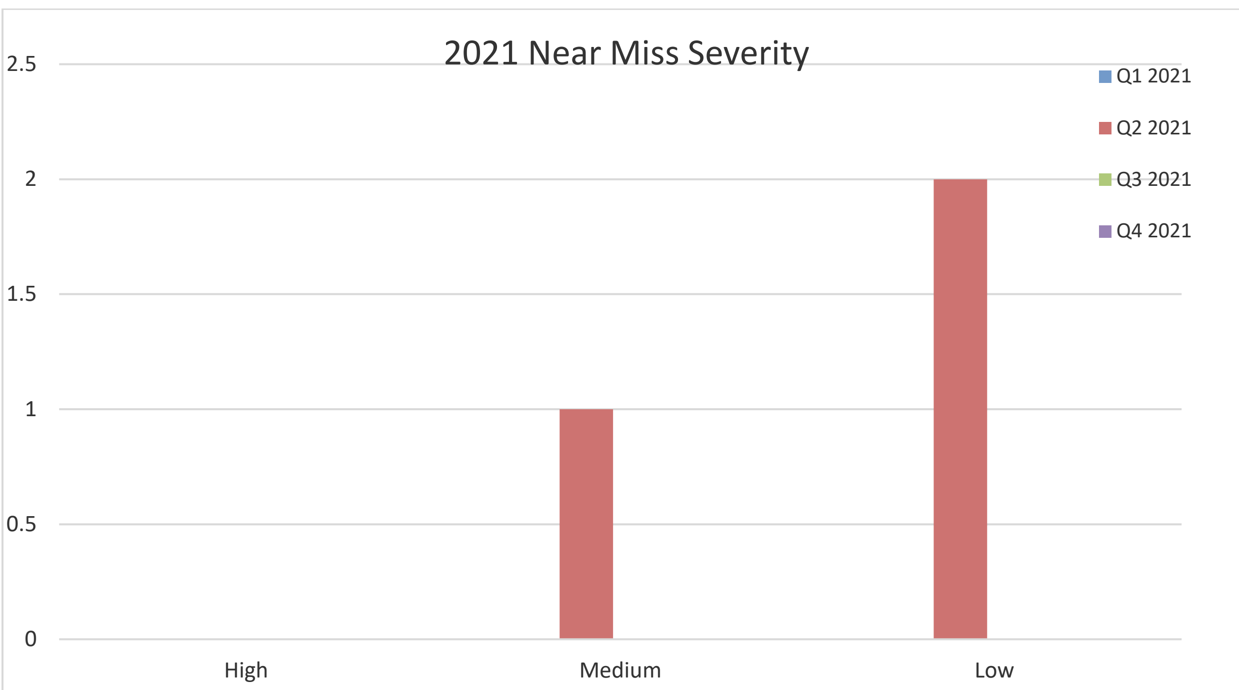
Historical Safety Statistics





Historical Safety Statistics





Synergy North Corporation
Board of Director's Corporate Evaluation Criteria

ASSET OBJECTIVES – FINANCIAL MANAGEMENT STRATEGY

Corporate Goal: Pursue being better in everything we do resulting in increased shareholder and customer value.

Financial Performance Evaluation allows the Board to monitor the financial performance of the utility relative to budgeted and historical measures. Provides a high-level overview of the financial health of the organization and facilitates the exercise of the Board's financial due diligence.

DESCRIPTION

- Monthly O&M Expenditures compared to budget, previous year and available industry benchmarks
- Capital Expenditures compared to budget and previous year
- Distribution Revenue compared to budget and previous year
- Presentation of key financial ratios

2021 OBJECTIVES	TARGET DATE(S)
• Manage Controllable Expenses to 2021 Budget levels	Q4
• Manage Capital Expenditures to 2021 Budget level	Q4
• Maintain financial ratios above minimum threshold (Subject to change to reflect impact of specific strategic initiatives)	Ongoing

FIRST QUARTER UPDATE

• OM&A Expenses below budget at Q1	On Target
• Distribution Revenue above budget at Q1	On Target
• CapEx expenditures above budget at Q1 *but behind plan (2020) – COVID-19*	On Target
• Financial Ratios in acceptable range	On Target

SECOND QUARTER UPDATE

• OM&A Expenses below budget at Q2	On Target
• Distribution Revenues slightly below budget at Q2	On Target
• CapEx expenditures above budget at Q2 *but behind plan (2020) – COVID-19*	On Target
• Financial Ratios in acceptable range	On Target

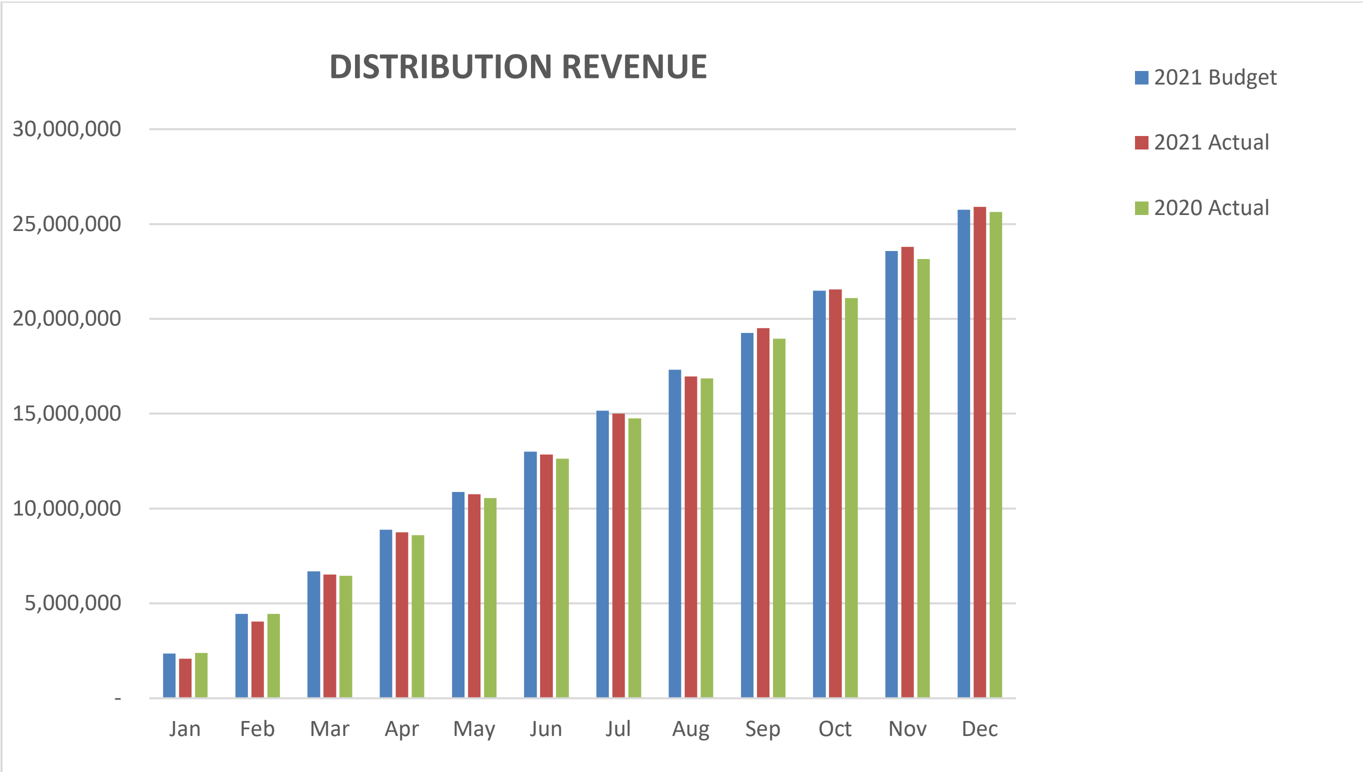
THIRD QUARTER UPDATE

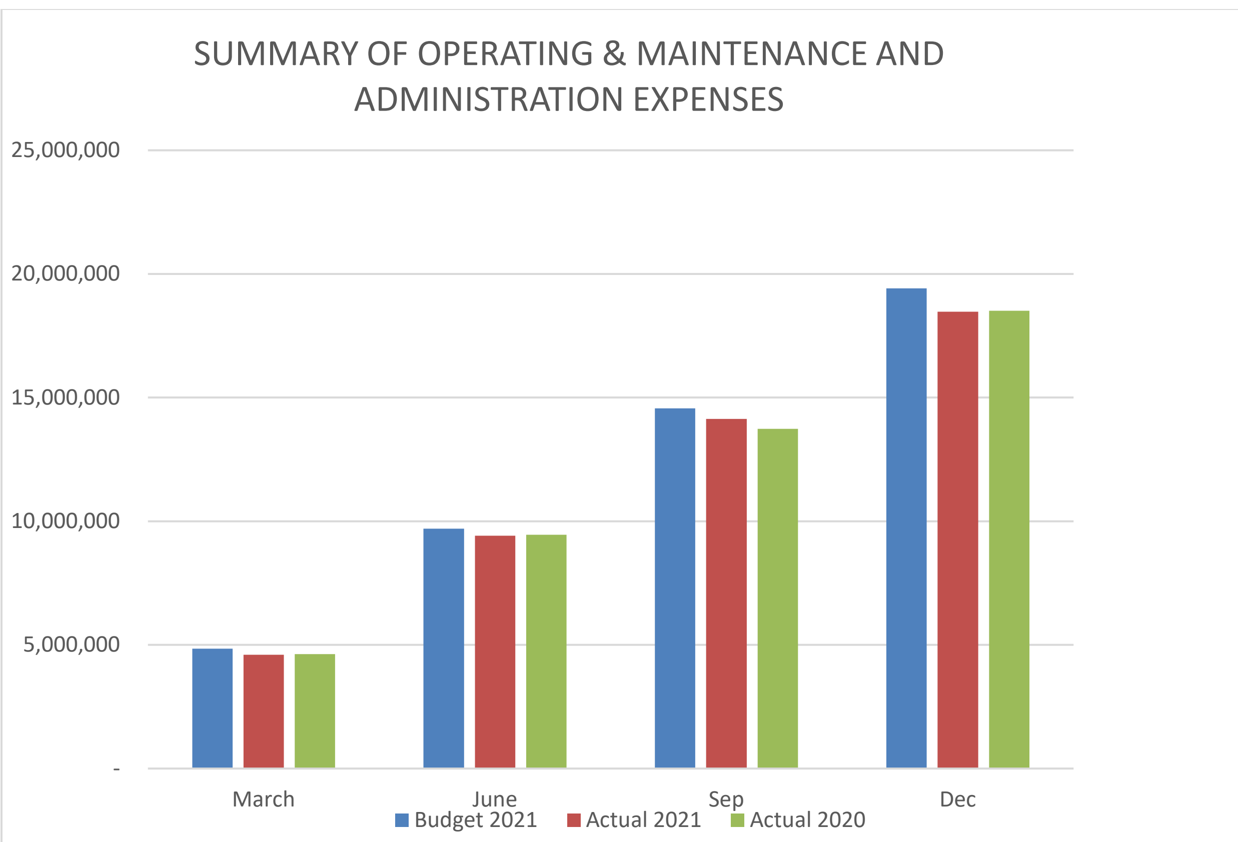
• OM&A Expenses below budget at Q3	On Target
• Distribution Revenues slightly above budget at Q3	On Target
• CapEx expenditures below budget at Q3 *but behind plan (2020) – COVID-19*	On Target
• Financial Ratios in acceptable range	On Target

FINAL QUARTER UPDATE

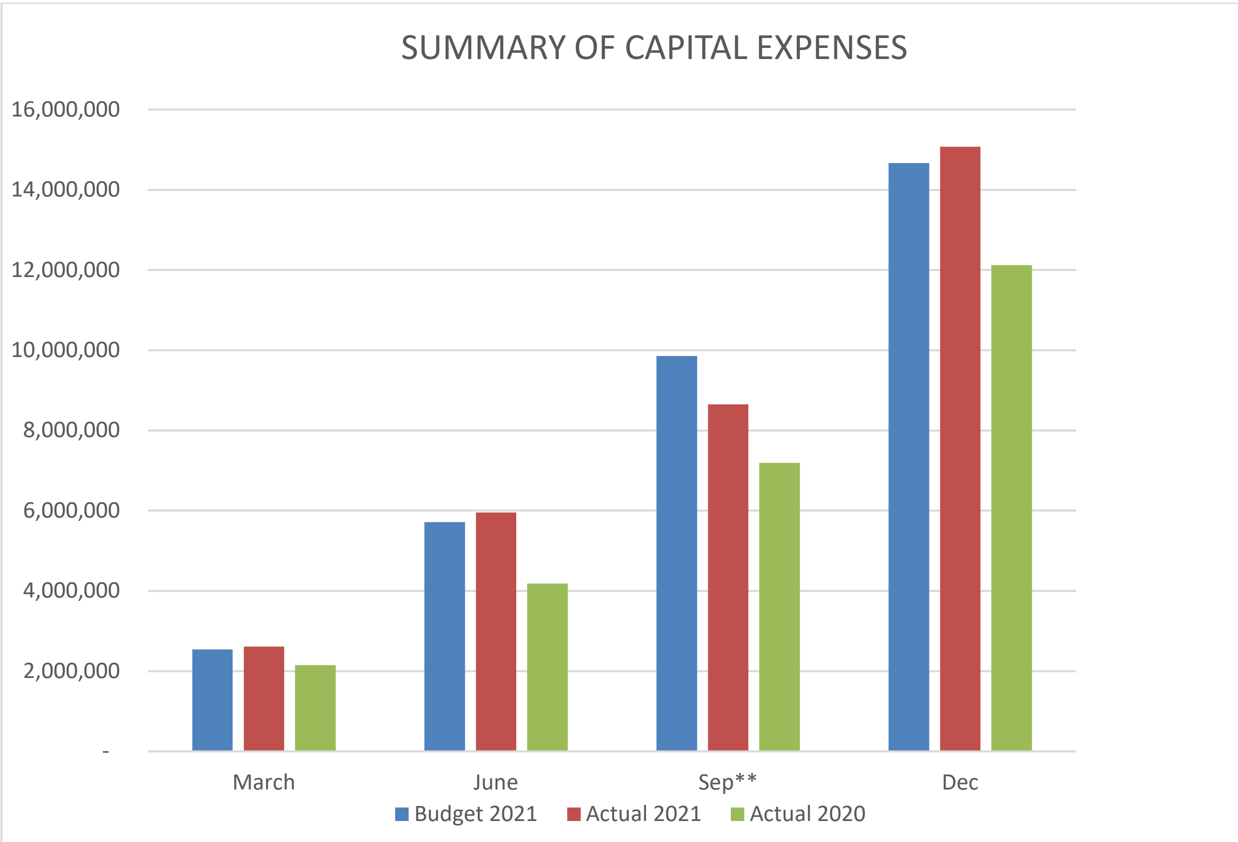
• OM&A Expenses below budget at Q4	On Target
• Distribution Revenues slightly above budget at Q4	On Target
• CapEx expenditures below budget at Q4 *but behind plan (2020) – COVID-19*	On Target
• Financial Ratios in acceptable range	On Target

Year To Date Summary Financial Results





Year To Date Summary Financial Results



**Note that the above budget by quarter calculation for capital is based on the actual quarter expenditures in the prior year.

Ratios as at December 31, 2021		Goal/ Requirement
Working Capital Ratio	1.71	> 1.00:1
Quick Ratio	1.56	> 1.00:1
Debt Capitalization Ratio	0.43	< 0.60:1
Bank Debt Capitalization Ratio	0.29	
Debt Service Coverage - TD	2.18	> 1.2:1

Synergy North Corporation
Board of Director's Corporate Evaluation Criteria

ASSET & CUSTOMER OBJECTIVES – OPERATIONAL PERFORMANCE MEASURES

Corporate Goal: Supply electricity and related services in a trustworthy, fair and dependable manner supporting our customers in achieving their goals.

Operational Performance Measures allow the Board to monitor the ongoing electricity reliability performance of the utility compared to historical performance. The Board can also monitor the ongoing operational performance of the utility as compared to Ontario Energy Board's Service Quality Indicator targets.

DESCRIPTION

- Monthly reliability indices as compared to previous years, available industry data and regulatory requirements.
- Year to date Service Quality Indicators performance compared with targets established by the OEB.

2021 OBJECTIVES	TARGET DATE(S)
• Reliability indices within the 5-year range of historical performance	Ongoing
• Service Quality Indicators meet/exceed OEB requirements	Ongoing
• Other internal measures as identified or developed in the future (i.e.: CDM program delivery, specific productivity factors, etc.)	Ongoing

FIRST QUARTER UPDATE

• Q1 Reliability Statistics excellent compared to historical	On Target
• Q1 OEB Service Indicator levels exceeded	On Target
• Q1 CapEx projects on schedule (2021) *but behind (2020) – COVID-19*	On Target

SECOND QUARTER UPDATE

• Q2 Reliability Statistics excellent compared to historical	On Target
• Q2 OEB Service Indicator levels exceeded	On Target
• Q2 CapEx projects on schedule (2021) *but behind (2020)- COVID-19*	On Target

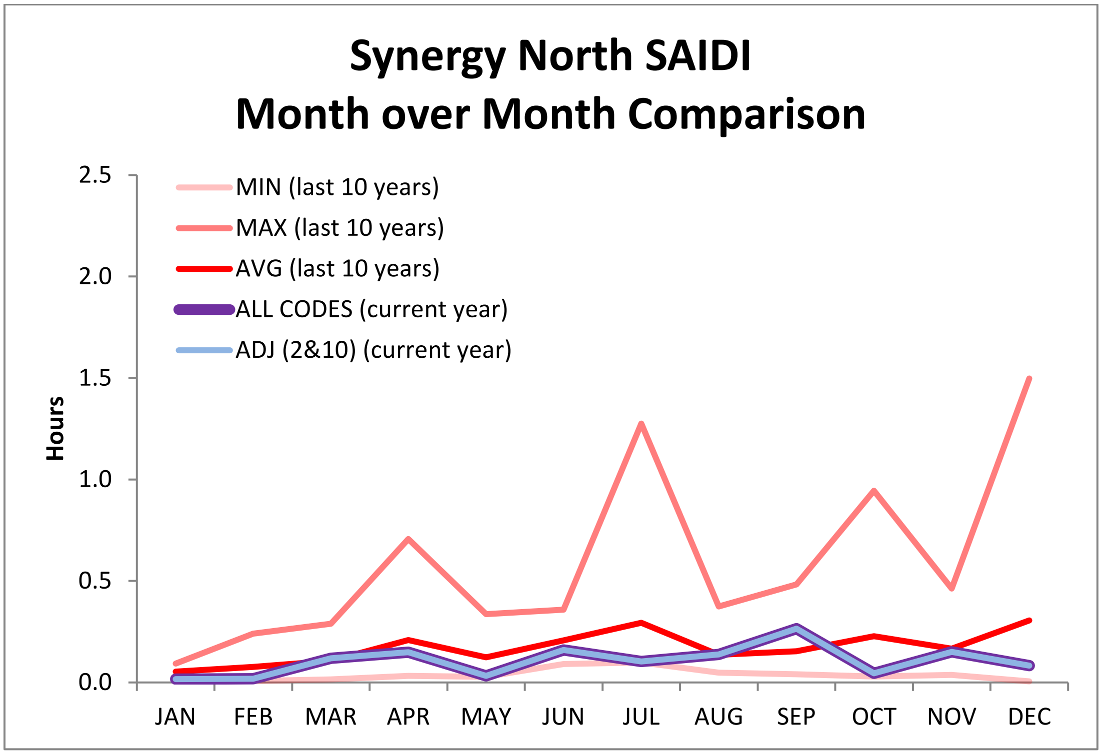
THIRD QUARTER UPDATE

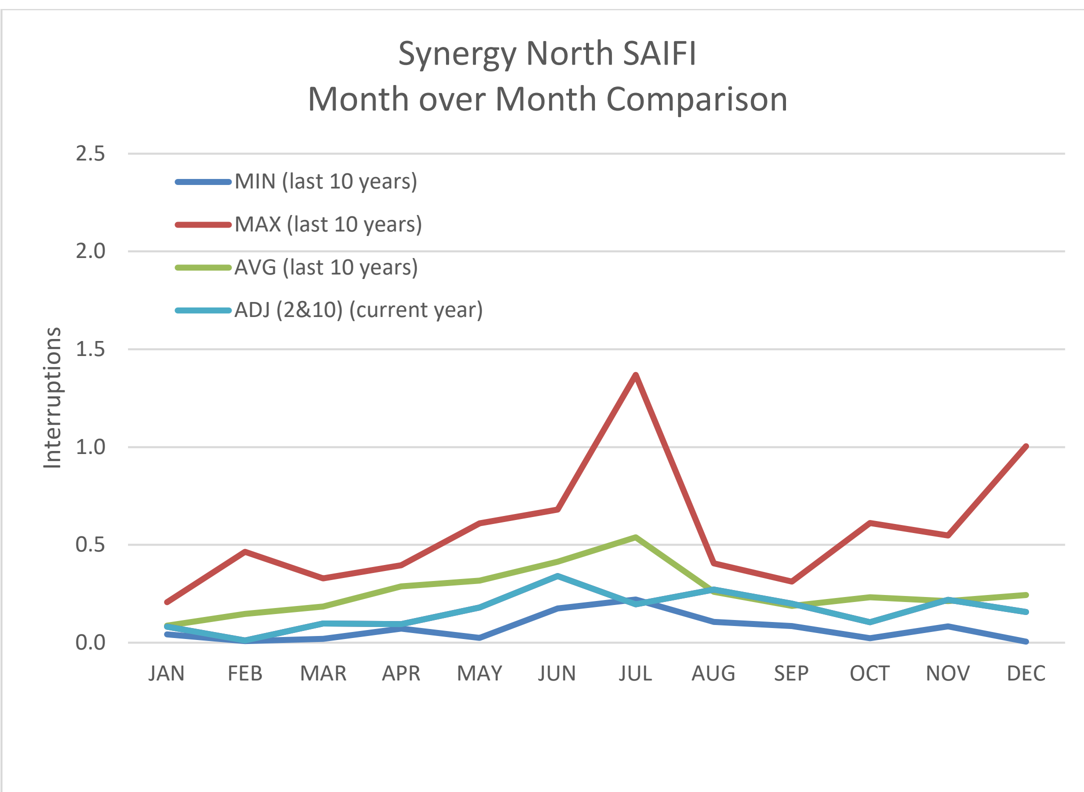
• Q3 Reliability Statistics excellent compared to historical	On Target
• Q3 OEB Service Indicator levels exceeded	On Target
• Q3 CapEx projects on schedule (2021) *but behind (2020)- COVID-19*	On Target

FINAL QUARTER UPDATE

• Q4 Reliability Statistics excellent compared to historical	On Target
• Q4 OEB Service Indicator levels exceeded	On Target
• Q4 CapEx projects on schedule (2021) *but behind (2020)- COVID-19*	On Target

<u>**Year To Date Operational Performance Indices**</u>

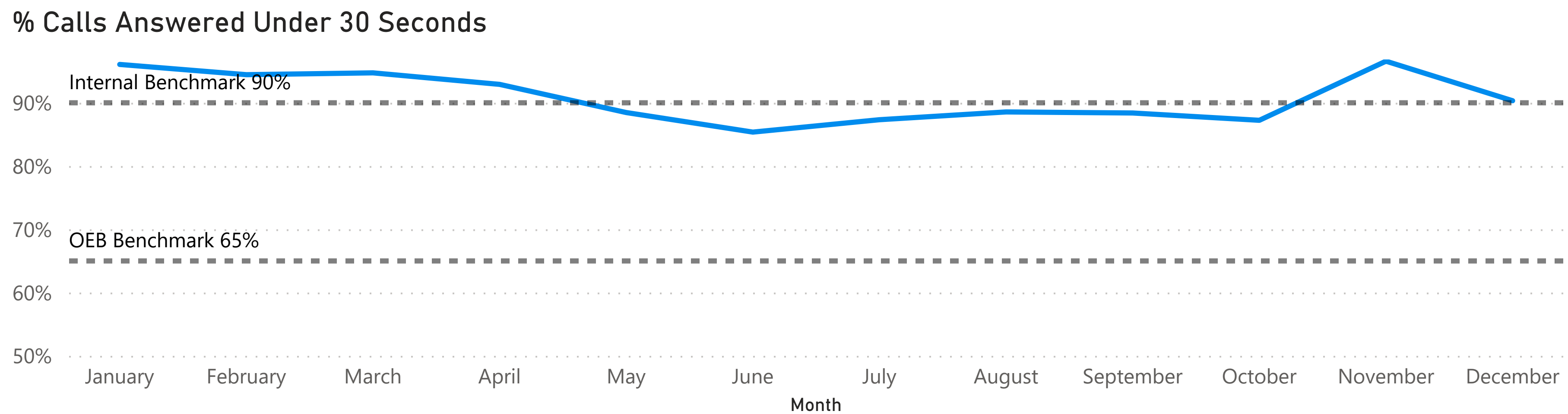


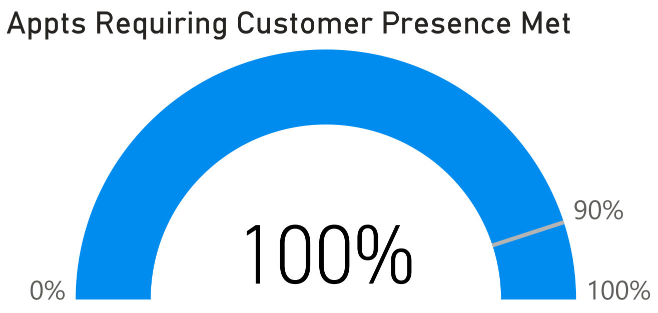


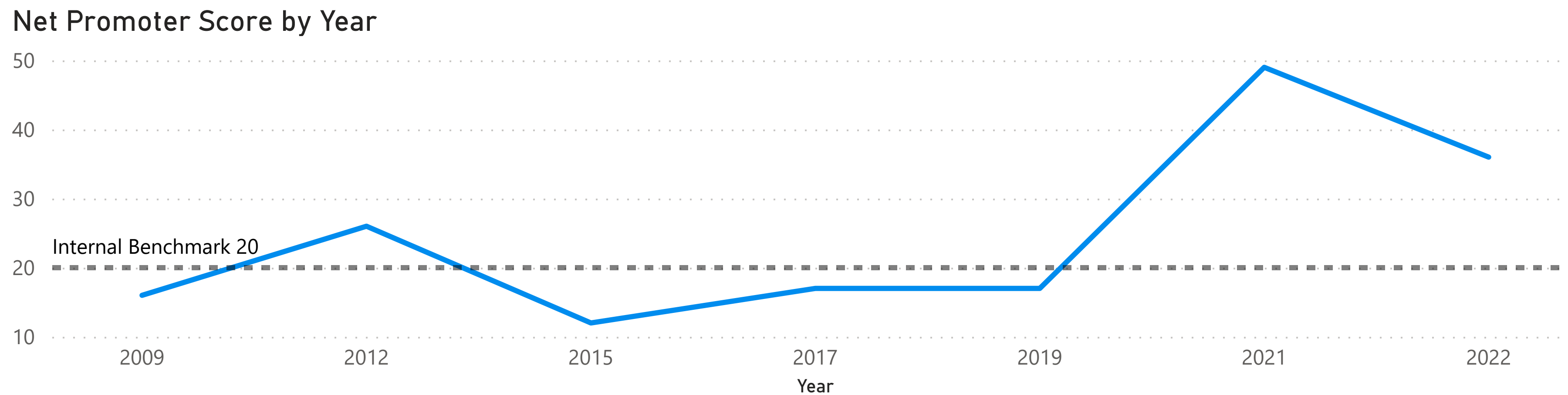
Year To Date Operational Performance Indices

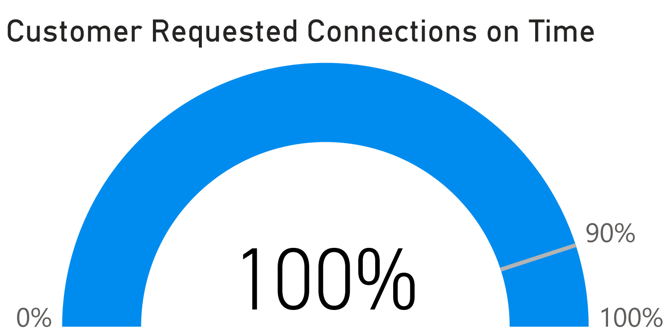
Customer Service Performance Indicators	Annual %	OEB Standard %	Months Below Standard
New Service Connection-low voltage	100	90	0
New Service Connection-high voltage	100	90	0
Underground Cable Locates	90.22	90	0
Telephone Accessibility	90.00	65	0
Appointments Met	100	90	0
Written Responses to inquiries	97	80	0
Emergency Response-Urban areas	100	80	0
Emergency Response-Rural areas	100	80	0

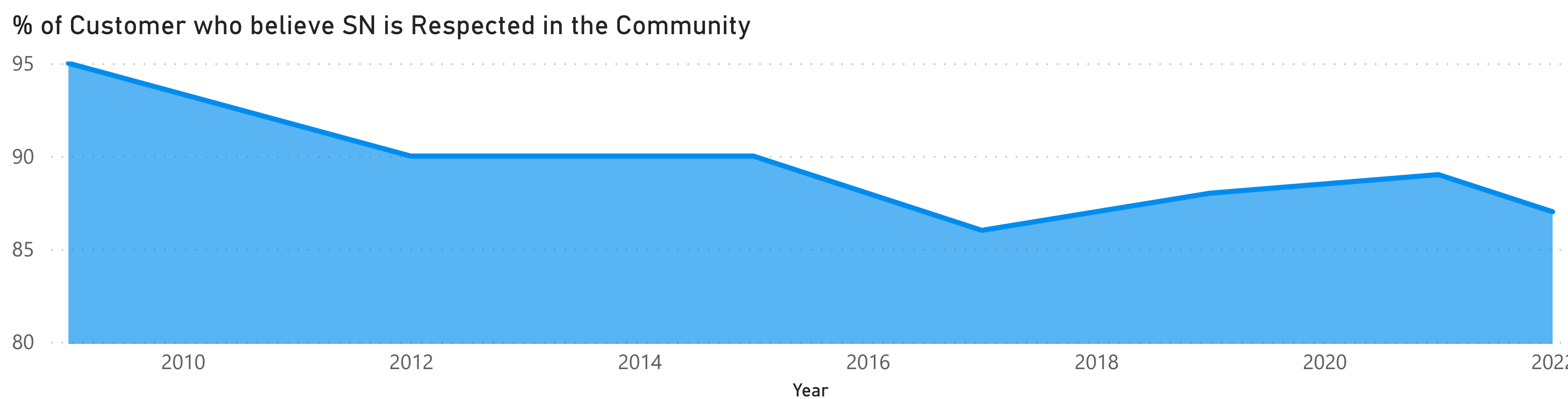
Customers


% Calls Answered Under 30 Seconds
Internal Benchmark 90%
OEB Benchmark 65%
90%
80%
70%
60%
50%
January
February
March
April
May
June
July
August
September
October
November
December
Month


Appts Requiring Customer Presence Met
100%
0%
90%
100%


Net Promoter Score by Year
50
40
30
20
10
Internal Benchmark 20
2009
2012
2015
2017
2019
2021
2022
Year


Customer Requested Connections on Time
100%
0%
90%
100%

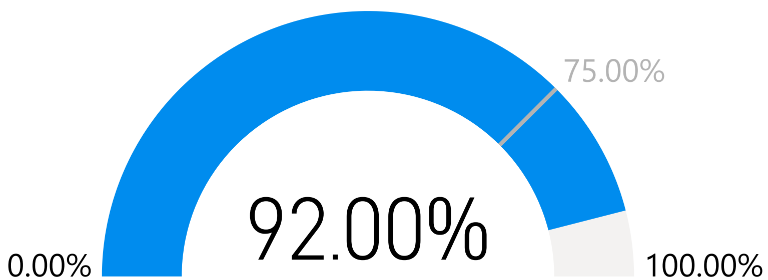

% of Customer who believe SN is Respected in the Community
95
90
85
80
2010
2012
2014
2016
2018
2020
2022
Year

People

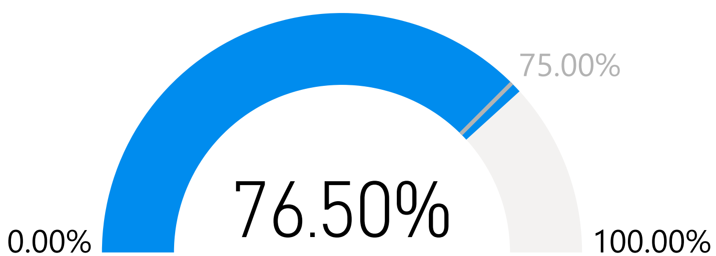
312

Days Since Lost Time Incident

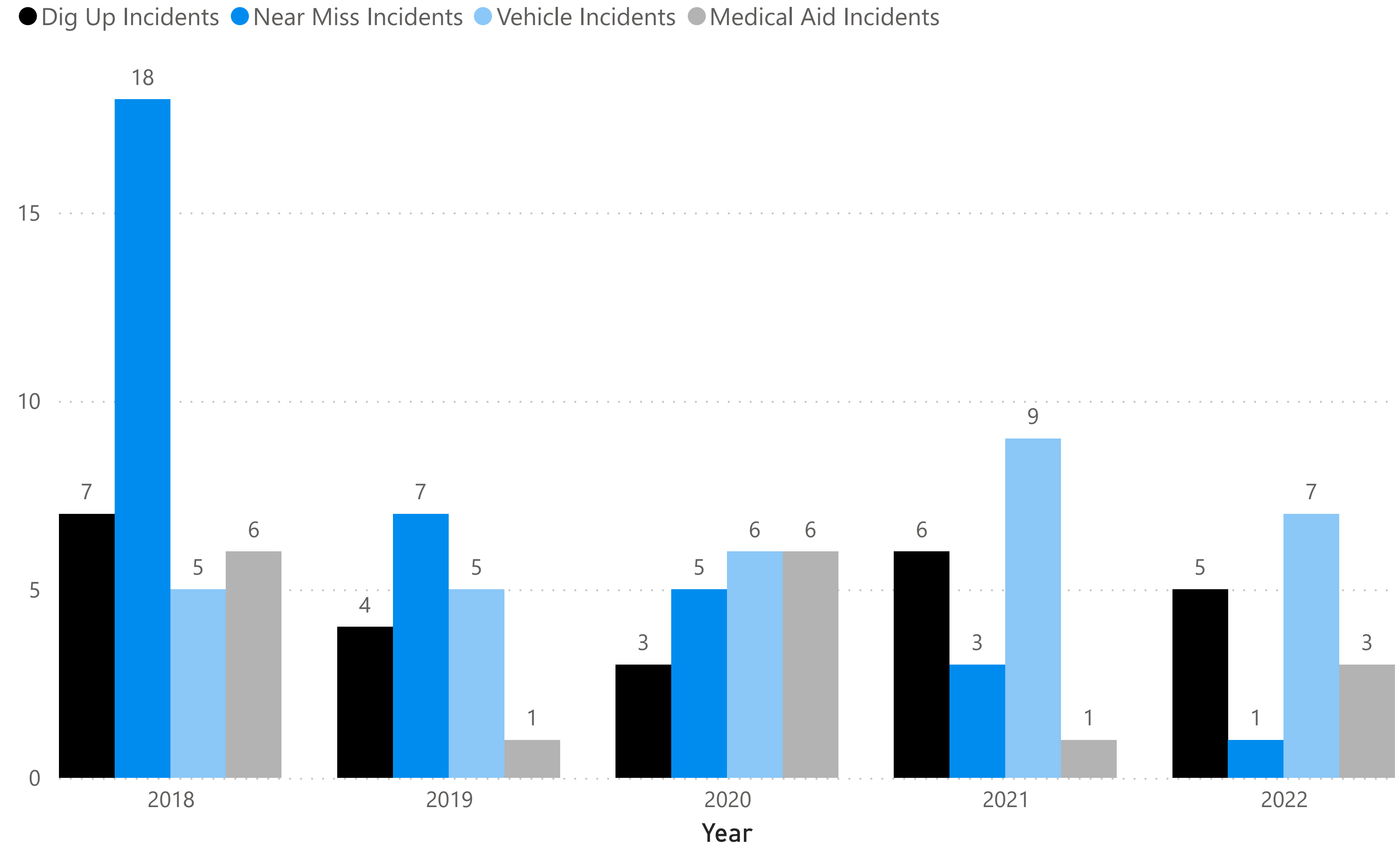
% of Employees who believe Safety is Top Priority



% of Employee Reporting Positive Engagement



Dig Up Incidents, Near Miss Incidents, Vehicle Incidents and Medical Aid Incidents by Year

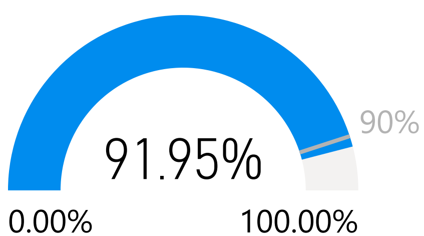


Industry Involvement

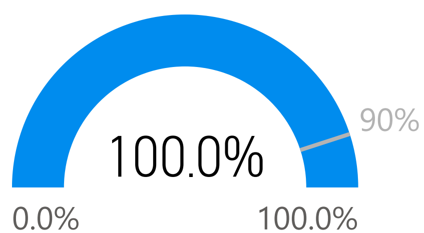
39	5	19
Distinct Groups/Committees	Leadership Postions	Different Employees

Assets Operations

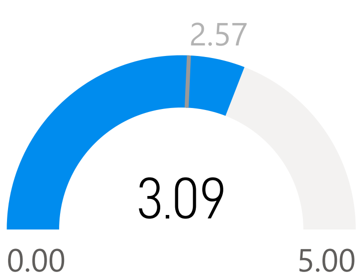
% Locates Performed On Time



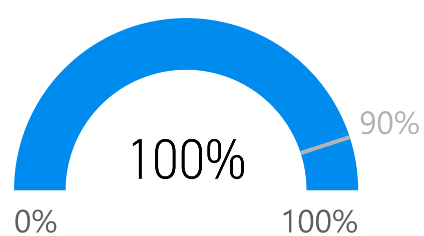
% Rural Emergency Response On Time and Target



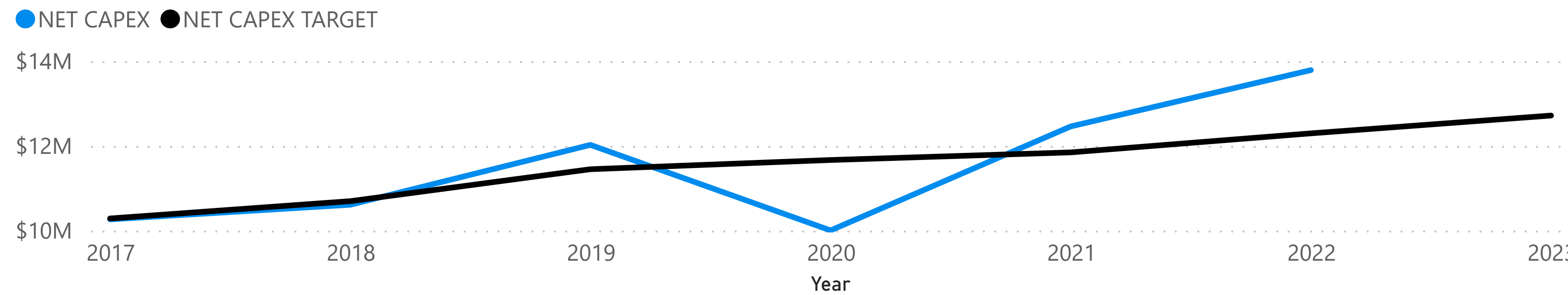
Centre for Internet Security Control Score



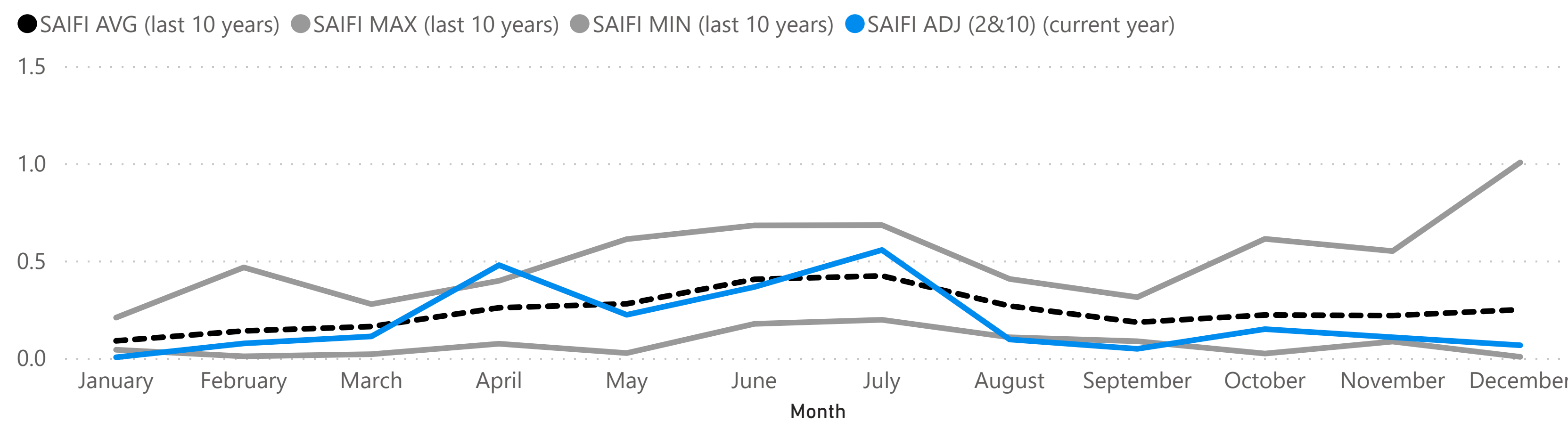
% Urban Emergency Response On Time and Target



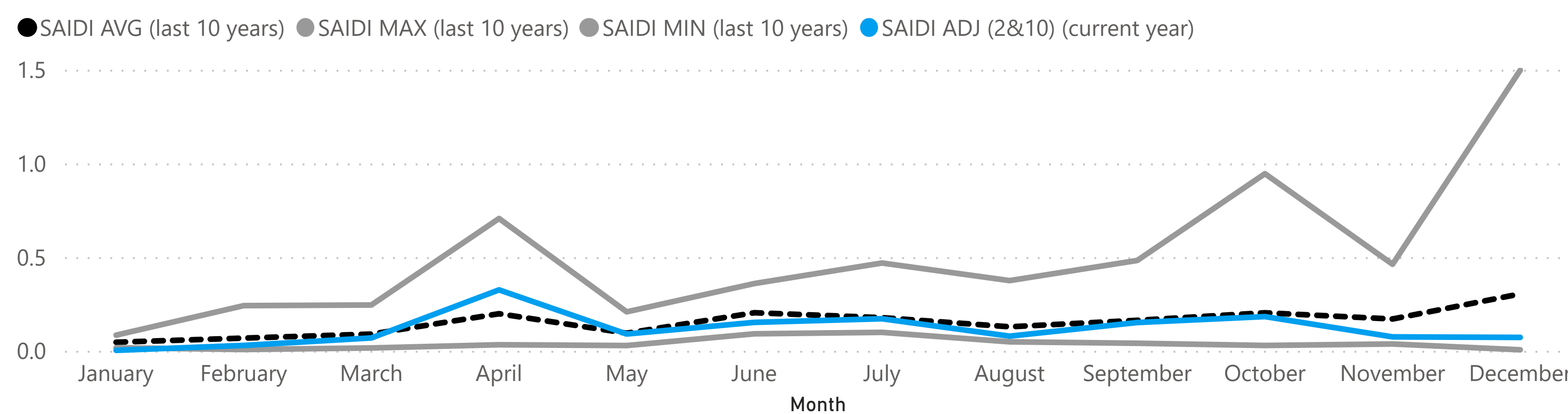
OEB Approved Capital vs. Net Capital by Year



SAIFI Last 10 years, Current Year by Month



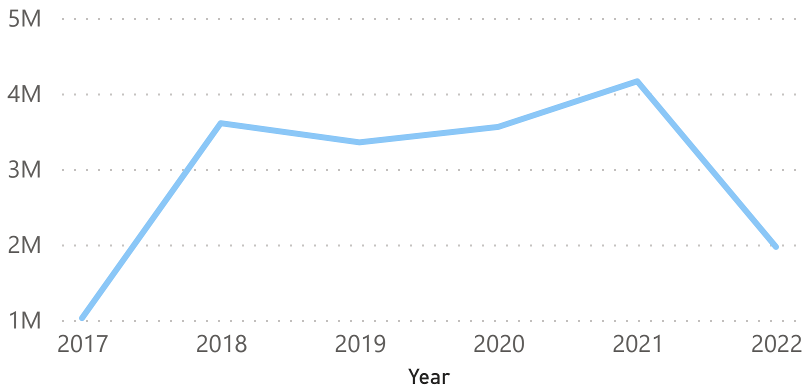
SAIDI Last 10 years, Current Year by Month



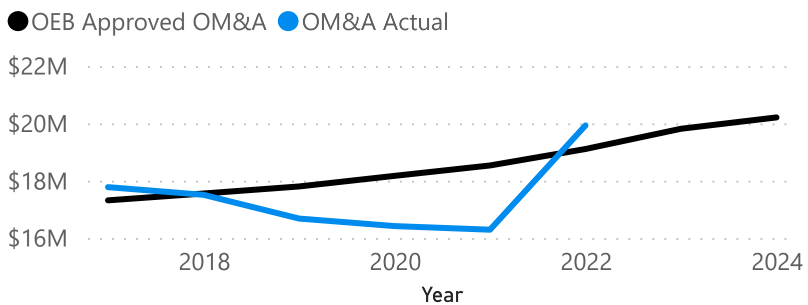
Assets

Financial

Net Income by Year

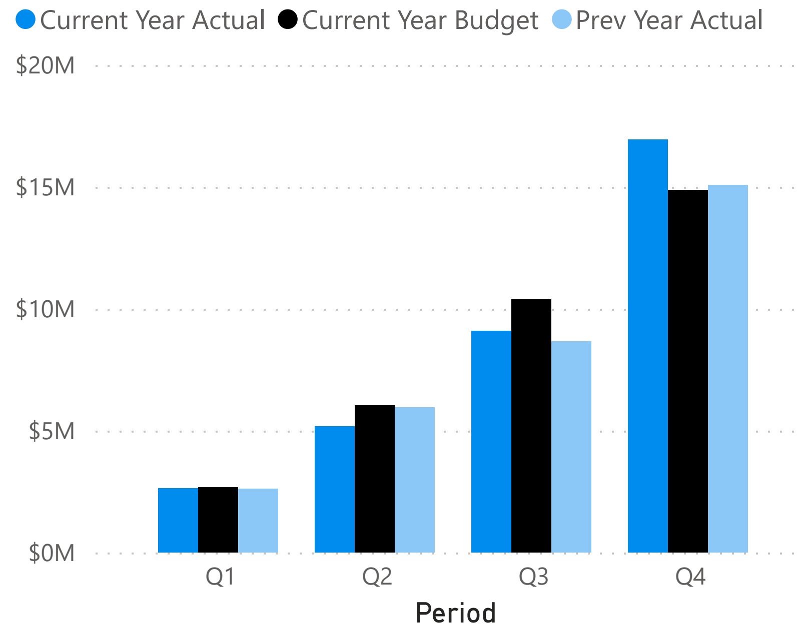


OEB Approved OM&A vs Actual by Year

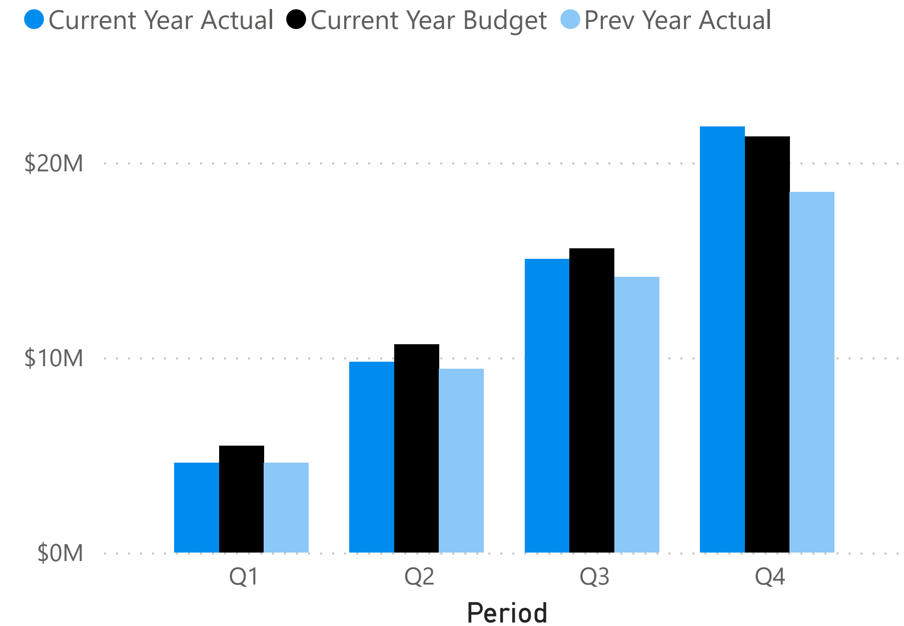


Financial Ratios	Actual	Target
Bank Debt Capitalization	0.32	< 0.60
Debt Capitalization	0.45	< 0.60
Debt Service Coverage	1.06	> 1.20
Quick	1.40	> 1.00
Working Capital	1.59	> 1.00

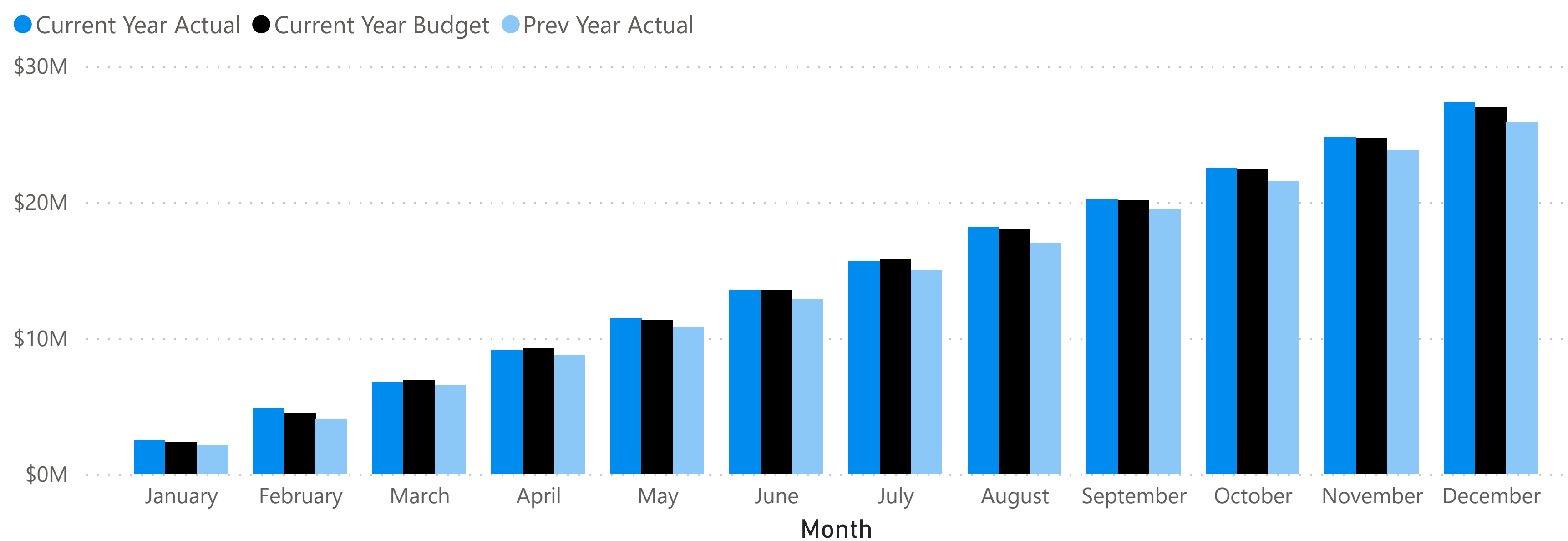
Capital Expense Summary by Period



OM&A Expense Summary by Period

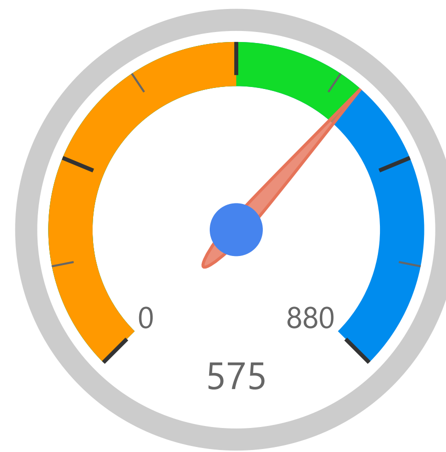


Cumulative Revenue Summary by Month

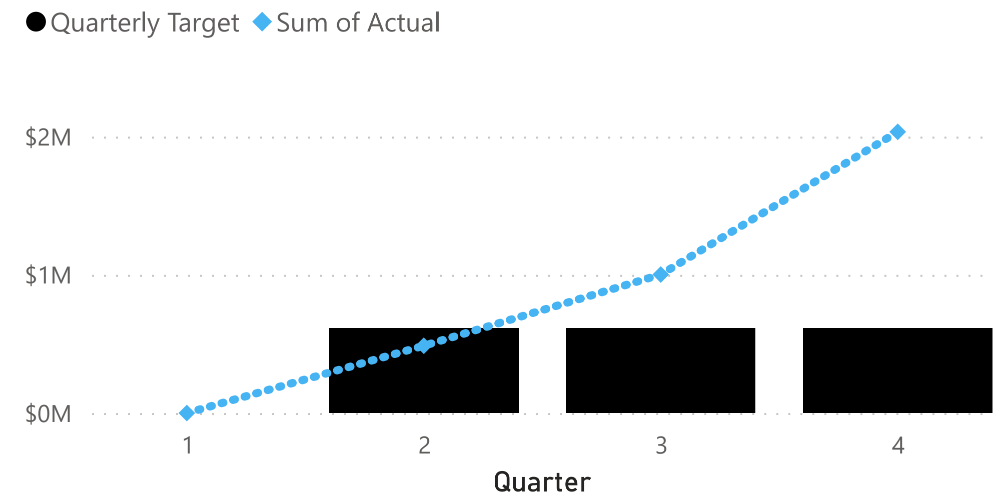


Strategic Initiatives

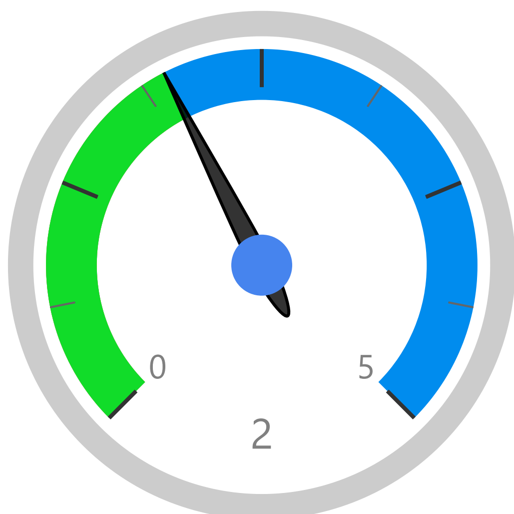
kM of Line Cleared within 1m



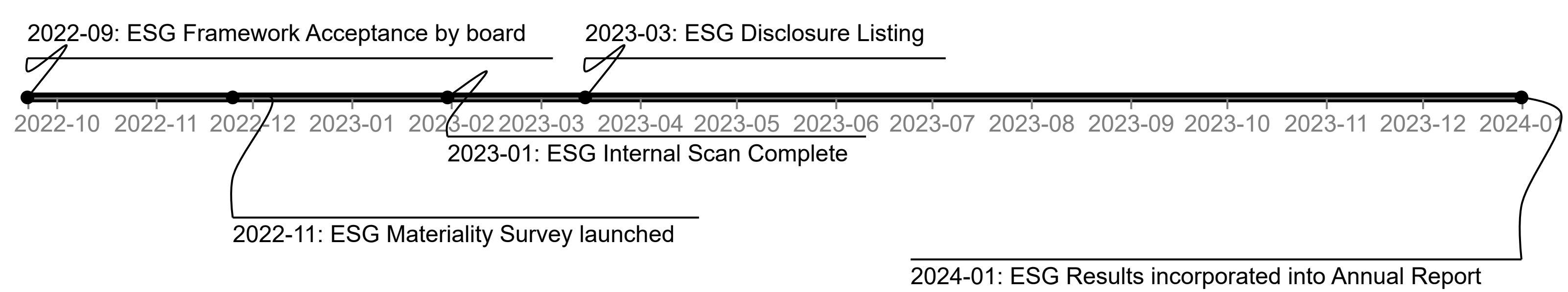
Vegetation Management Plan



Business Continuity Plan - Business Units Completed



ESG Framework



ATTACHMENT 1-3:

Dividend Letters to Shareholders

Ms. Kyle Attanasio
Chief Administrative Office
City of Kenora
1 Main Street S
Kenora, ON

Mr. Kyle Attanasio,

SYNERGY NORTH Corporation Dividend to the City of Kenora

It is with great pleasure that SYNERGY NORTH Corporation (SNC) includes in this letter a dividend cheque of $24,930 as declared on April 27th, 2023. The cheque payable to the City of Kenora represents the City of Kenora's 8.31% ownership of SNC.

This dividend is a special merger efficiency dividend. During the 2022 fiscal year SNC declared a special merger efficiency dividend of $300,000 resulting in a declared dividend of $2.739576 per share. You will see that the special merger efficiency dividend declared here was declared the previous year. As anticipated, global inflation impacted the utility financially. Also, the utility embarked on a vegetation management to address regulatory issues. This spending was unfunded in rates.

Needless to say, the merger has been both a financial and operational success and we have been delivering pre-tax merger savings of approximately $900,000 annually. The Unanimous Shareholder Agreement allows one more year of special merger efficiency dividends. After this period, and coinciding with electricity rates for May 1, 2024, merger efficiencies will be built into electricity distribution rates and will directly benefit SNC's customers.

I continue to raise to your attention the issue of the extraordinary inflationary pressures we are all facing. Additionally, SNC is in year 2 of its vegetation plan that is unfunded in rates. As well, I need to note that interest will begin to be paid by SNC to the City of Thunder Bay commencing in December of 2023. The interest payments are not currently funded in rates and will not be until approved in April 2024 for May 2024 rates. Finally, the City of Kenora should expect a second loan payment from SNC within the next month. These are important things to note at this time, as these items will likely impact on the utility's ability to dividend in the future.

If you have any questions, please do not hesitate to contact me.

34 CUMBERLAND STREET NORTH | THUNDER BAY, ON | P7A 4L4 | T: (807) 343-1111 | 1-833-428-1451 synergynorth.ca

Yours Truly,

Tim Wilson, MBA
President & CEO

34 CUMBERLAND STREET NORTH | THUNDER BAY, ON | P7A 4L4 | T: (807) 343-1111 | 1-833-428-1451 synergynorth.ca

THUNDER BAY HYDRO

34 North Cumberland Street
Thunder Bay, ON P7A 4L4
tel (807) 343-1111
www.tbhydro.com

Ms. Emma Westover CPA, CA
Acting General Manager-Corporate Services & Long-Term Care and City Treasurer
City of Thunder Bay
500 E. Donald Street
Thunder Bay, ON

Ms. Westover,

Thunder Bay Hydro Corporation Dividend to the City of Thunder Bay

It is with great pleasure that Thunder Bay Hydro Corporation (TBHC) includes in this letter a dividend cheque of $325,070 as declared on April 28. The cheque payable to the City of Thunder Bay represents TBHC's combined sum of the Solar PV and Merger Efficiency dividends declared by SYNERGY NORTH Corporation (SNC) on April 27, 2023.

TBHC maintains 100% ownership of SNC's Solar PV assets through a separate share class. The $50,000 dividend received is being passed through to the City. You will see that the dividend declared here is less than what was declared the previous year. 2022 saw extremely inclement weather that significantly impacted solar operations.

The remaining $275,070.00 relates to TBHC's share of SNC's special merger efficiency dividend. During the 2022 fiscal year, SNC declared a special merger efficiency dividend of $300,000 resulting in a declared dividend of $2.739576 per share. TBHC owns 109,506 shares of SNC. The $275,070 dividend received is being passed through to the City. You will see that the special merger efficiency dividend declared here is less than what was declared the previous year. As anticipated, global inflation impacted the utility financially. Also, the utility embarked on a vegetation management to address regulatory issues. This spending was unfunded in rates.

Needless to say, the merger has been both a financial and operational success, and we have been delivering pre-tax merger savings of approximately $900,000 annually. The Unanimous Shareholder Agreement allows one more year of special merger efficiency dividends. After this period, merger efficiencies will be built into electricity distribution rates and directly benefit SNC's customers.

I continue to raise to your attention the extraordinary inflationary pressures we are all facing, specifically across all subsidiaries of TBHC. Additionally, SNC is in year 2 of its vegetation plan that is unfunded in rates. Finally, I need to note that interest will begin to be paid by SNC to the City commencing in December of 2023. The interest payments are not currently funded in rates and will not be until approved in April 2024 for May 2024 rates. These are important notes at this time, as these items will likely have impact on the utility's ability to dividend in the future.

If you have any questions, please do not hesitate to contact me.

Yours Truly,

Tim Wilson, MBA
President & CEO

THUNDER BAY HYDRO

34 North Cumberland Street
Thunder Bay, ON P7A 4L4
tel (807) 343-1111
www.tbhydro.com

Ms. Linda Evans CPA, CA
General Manager-Corporate Services & Long Term Care and City Treasurer
City of Thunder Bay
500 E. Donald Street
Thunder Bay, ON

Ms. Evans

Thunder Bay Hydro Corporation Dividend to the City of Thunder Bay

It is with great pleasure that Thunder Bay Hydro Corporation (TBHC) includes in this letter a dividend cheque of $659,065 as declared on April 29. The cheque payable to the City of Thunder Bay represents TBHC's combined sum of the Solar PV and Merger Efficiency dividends declared by SYNERGY NORTH on April 28, 2022.

TBHC maintains 100% ownership of SYNERGY NORTH's Solar PV assets through a separate share class. The $75,000 dividend received is being passed through to the City.

The remaining $584,065.00 relates to TBHC's share of SYNERGY NORTH's special merger efficiency dividend. During the 2021 fiscal year, net savings were $637,000 resulting in a declared dividend of $5.817033 per share. TBHC owns 109,506 shares of SYNERGY NORTH. The merger has been both a financial and operational success, and we have been delivering pre-tax merger savings of approximately $900,000 annually. For 2022 through 2023, these savings should be available for distribution to Shareholders through future Special Dividend declarations as allowed in the Unanimous Shareholder Agreement. After this period, merger efficiencies will be built into electricity distribution rates and directly benefit Synergy North's customers.

As a note, I raise to your attention the issue of the extraordinary inflationary pressures we are all facing and specifically across all subsidiaries of TBHC. This global issue may impact SNC's and TBHC's ability to issue a dividend in the future. This is an important note at this time.

If you have any questions, please do not hesitate to contact me.

Yours Truly,

Tim Wilson, MBA
President & CEO

Committed to Customer Satisfaction

THUNDER BAY
HYDRO

34 North Cumberland Street
Thunder Bay, ON P7A 4L4
tel (807) 343-1111
www.tbhydro.com

October 15, 2021

Dana Earle
City Clerk
City of Thunder Bay
500 Donald Street E
P.O. Box 800
Thunder Bay, ON
P7C 5K4

Dear Ms. Earle:

Re: Dividend Payment

Enclosed is a dividend cheque for $500,000 from Thunder Bay Hydro Corporation. City Council passed a resolution requesting a $500,000 dividend payment from Thunder Bay Hydro Corporation in a letter dated March 10, 2020, to former President & CEO Robert Mace. Due to the COVID-19 pandemic, the dividend declaration was delayed.

Thunder Bay Hydro Corporation Board of Directors passed a resolution on October 5, 2021, meeting to declare a dividend to the City of Thunder Bay.

As always, please do not hesitate to contact me if you require additional information.

Sincerely,

Tim Wilson, MBA
President & CEO

TW/amc

ATTACHMENT 1-4:

4kV Conversion

also address heavily aged assets which fall outside of the scope of the annual conversions, TBHEDI will continue to conduct suspect pole replacements on a 'concern' driven basis. Over the past three years, suspect pole changes driven by concerns have averaged 120 units per year.

4kV Conversion Drivers

In addition to the overall age of the 4kV distributed assets, the 4kV conversion initiative is also driven by the economics of the following;

- Replacement of the substantially aged 4kV distribution substation assets;
- Ongoing costs associated with the maintenance of the 4kV distribution substation assets; and,
- Distribution system losses associated with the 4kV sub-network.
- The incremental cost of erecting, stringing and framing a pole which supports 25kV distribution vs. 4kV distribution is negligible.

4kV Distribution Station Investments

TBHEDI's 4kV distribution network depends on 14 substations to step down the 25kV primary to 4kV secondary. TBHEDI inspects each of these facilities monthly and performs maintenance as required.

The average age of TBHEDI's 4kV substation transformers and substation breakers are both 53.8 years. The Kinetrics report[42] estimates a typical useful life for each of these assets to be 45 years and a maximum useful life to be 60 and 65 years respectively. As such, TBHEDI can expect to replace a significant portion of these assets within the next

[42] "Asset Depreciation Study for the Ontario Energy Board", conducted by Kinetrics, July 8, 2010.

10 years. The approximate replacement cost of a 4kV substation and all associated components, less contingency and overheads, is as follows (Table 54);

Distribution Station Component	Estimated Cost
4MVA, 24.94kV/4.16kV, Oil Immersed Power Transformer (Qty 2)	$250,000
4kV, 1200A Breaker Lineup (8 Breakers/Substation Average)	$310,000
DC Supply Components	$20,000
Power and Instrument Transformers	$28,000
Protective Relays	$17,000
Ground & Test Device	$55,000
Power Quality Meters	$25,000
Current Transformers	$20,000
Infrared Viewing Ports	$25,000
Auxiliary Substation Components	$15,000
Civil Work	$200,000
Engineering and Design	$100,000
Labour, Trucking, and Additional Materials	$225,000
Total:	$1,270,000

Table 54 - Estimated TBHEDI Cost to Rebuild One 4kV Substation

Assuming a major substation rebuild takes place annually every year from 2013-2027, the net present cost to TBHEDI represented by these replacements (at a 2% CPI[43]) is $15.4M.

Rather than replacing these assets, TBHEDI will decommission the 4kV substation assets as their associated areas are converted.

The costs associated with all of the decommissioning and subsequent demolition activities for the 4 kV substations will be captured within the specific substation OM&A accounts. As the 4 kV substations have differing configurations and civil infrastructure (some have buildings some do not, some have 1 transformer while others have 2 transformers etc.) the individual substation cost for decommissioning and demolishing

[43] CPI: Consumer Pricing Index

will differ substantially. Detailed below is the anticipated preparation and demolition costs in today's dollars for each substation without contingency or overheads applied

Substation	Subtotal
Mary Street	$56,000
Brock Street	$32,000
McPherson Avenue	$26,000
Balsam Street	$5,500
Windemere Avenue	$56,000
Hardisty Street	$32,000
Vickers Street	$25,000
High Street	$7,000
Grenville Avenue	$50,000
Camelot Street	$85,000
Algoma Street	$55,000
MacDonnell Street	$56,000
Mountdale Avenue	$26,000
Donald Street	$55,000
Combined Overall Total:	$566,500
Average 4kV Substation Decommissioning Cost:	$40,464

Thunder Bay Hydro staff and speciality service contractors will be utilized to complete select activities as required at each of the substations. The activities are listed below;

Thunder Bay Hydro staff will be used to:
- isolate and de-energize all sources of AC power,
- remove all batteries,
- remove any >2 ppm PCB oil,
- remove any >2 ppm PCB equipment
- remove any equipment that can be utilized again

Specialty Service Contractors will be used for:
- asbestos containing material (ACM) abatement
- lead paint sampling and laboratory analysis
- lead paint abatement (if required)
- crane services for hoisting
- haulage or transportation services
- civil works demolition and site reclamation services
- neighbour information package delivery services

Assuming the average substation decommissioning cost of $40,464, the net present value for these activities (assuming the same schedule and CPI as above) is $489,867. Therefore, in terms of only capital replacement costs, conversion of the 4kV and subsequent decommissioning of the substations represents an estimated cost savings of $14.9M over 14 years.

4kV Distribution Station Maintenance Costs

TBHEDI performs a visual inspection of all substations monthly and a detailed inspection of all substations every three years. This regime includes regular inspection and maintenance of the following facilities as their conditions require;

- Substation enclosure and fencing;
- Breakers and switchgear;
- Power transformers; and,
- Auxiliary station equipment (AC and DC systems, protective relaying, SCADA equipment, , remote terminal units, metering, instrument transformers, lightning arrestors, insulators, bus connections, steel structures, foundations, oil containment, ducts / conduits etc.).

The substation maintenance regime also includes event related maintenance due to faults or component failure, for the purposes of this section the costs for these activities are distributed across the 4kV substation population.

TBHEDI’s annual costs associated with the scheduled and emergency maintenance of the 4kV substation population is estimated to be $14,610 per station, per year ($204,540 total per year).

Assuming that TBHEDI will decommission one substation per year from 2013-2027, the net present value of the deferred maintenance cost associated with the 4kV substations is approximately $7.5M (assumes 13 stations remain in 2013, 12 in 2014, and so on).

4 kV System Losses

The conductors that are utilized in the distribution network contain a resistive component which dissipates power in the form of heat when supporting electrical loads. Heat dissipated by conductors is a component of electrical loss and represents a monetary loss to the LDC.

Typically, conductors are sized such that they can economically perform the function for which they are designed while limiting the amount of energy lost through heating. Designers must strike a balance whereby losses are minimized and yet the conductor remains economical and practical from a construction perspective.

The power lost to the heating of a conductor is proportional to the square of the current and the resistance of the conductor. Further, the current demanded by an electrical load is proportional to the voltage multiplied by the current. As such, a load connected directly to the 25kv network will have a current demand equivalent to 1/6th that of an equivalent 4kV load.

TBHEDI has performed an analysis of its present system where the losses sustained in the 4kV sub-network are compared to the losses sustained upon conversion of that network to 25kV. The result of this study estimates that the net loss reduction resulting from the voltage conversion (and hence reduced network current) may amount to $500,000 per year, projecting this savings over the same 2013-2027 period as before results in a net present savings of approximately $3.4M.

To summarize, TBHEDI anticipates that the conversion of the 4kV to 25kV as a sub-initiative to the Above Ground Asset Renewal Program will result in a net savings of $25.8M[44] due to deferral of maintenance activities, equipment replacements, and distribution system losses.

---

[44] Assuming a CPI of 2%, a 14 year schedule (1 year per substation), and in 2012 dollars

ATTACHMENT 1-5:

Phase 2 Survey

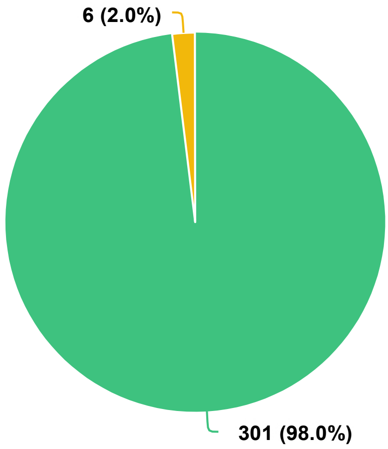
Investment Planning Survey: Phase Two

SURVEY RESPONSE REPORT
23 June 2022 - 11 June 2023

PROJECT NAME:
Help Shape Our Future Plans

SURVEY QUESTIONS

Q1 Are you a SYNERGY NORTH customer?

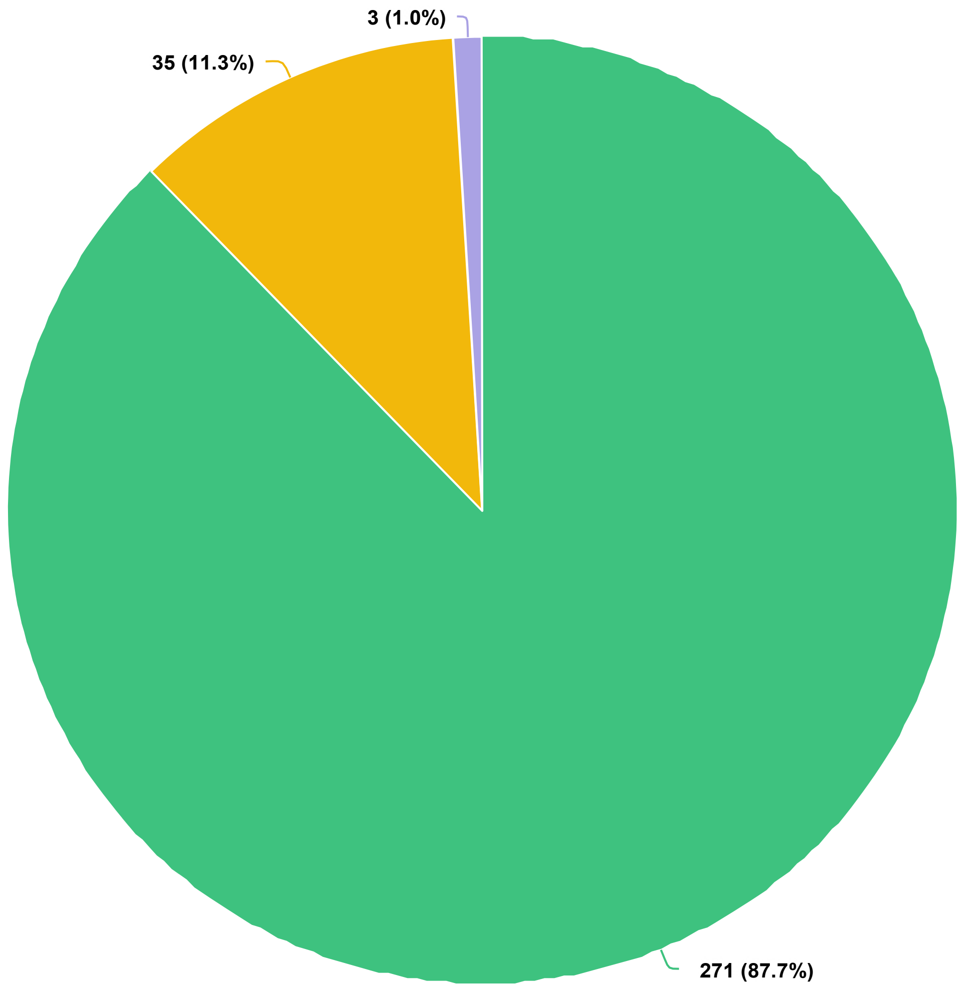


Question options

Yes No

Optional question (307 response(s), 2 skipped)
Question type: Radio Button Question

Q2 Do you have primary responsibility for paying the SYNERGY NORTH electricity bill in your household?

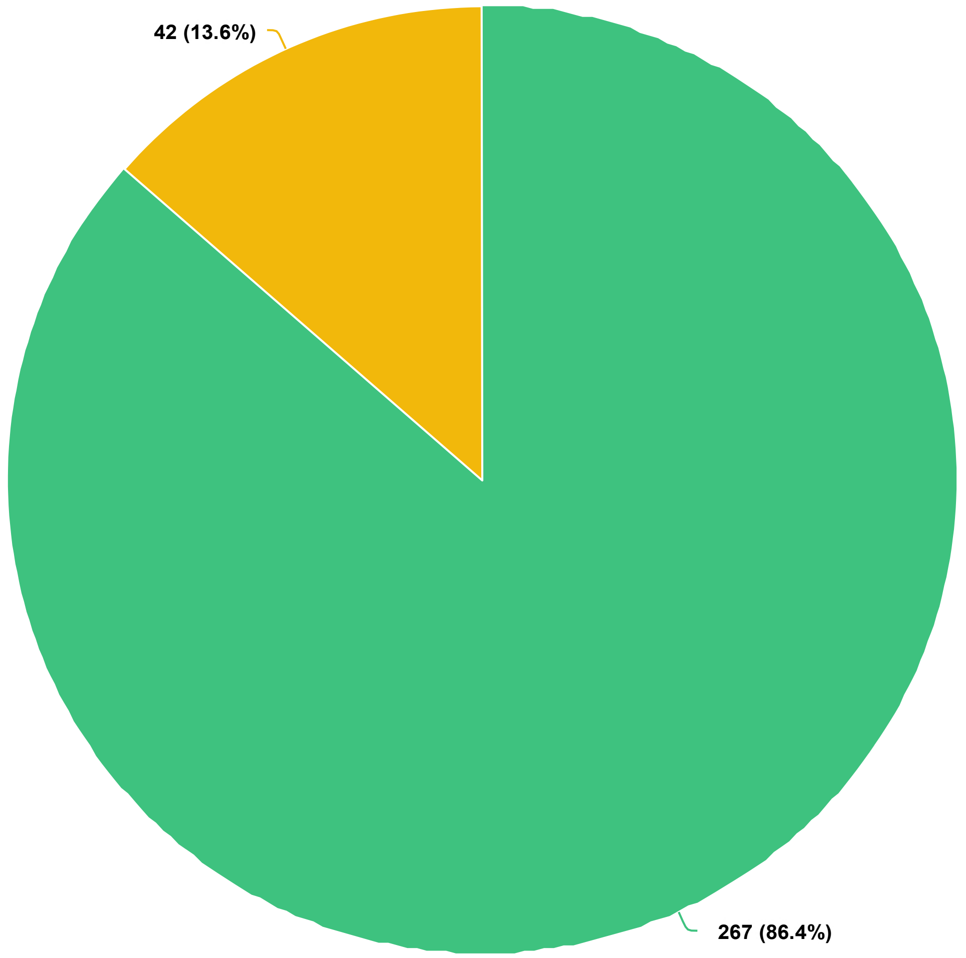


Question options

- I have primary responsibility for paying the SYNERGY NORTH electricity bill.
- Someone else in my household has primary responsibility for paying the SYNERGY NORTH bill.
- No one in my household has responsibility for paying the SYNERGY NORTH bill.

Optional question (309 response(s), 0 skipped)
Question type: Radio Button Question

Q3 Do you live in Kenora, ON or Thunder Bay, ON?

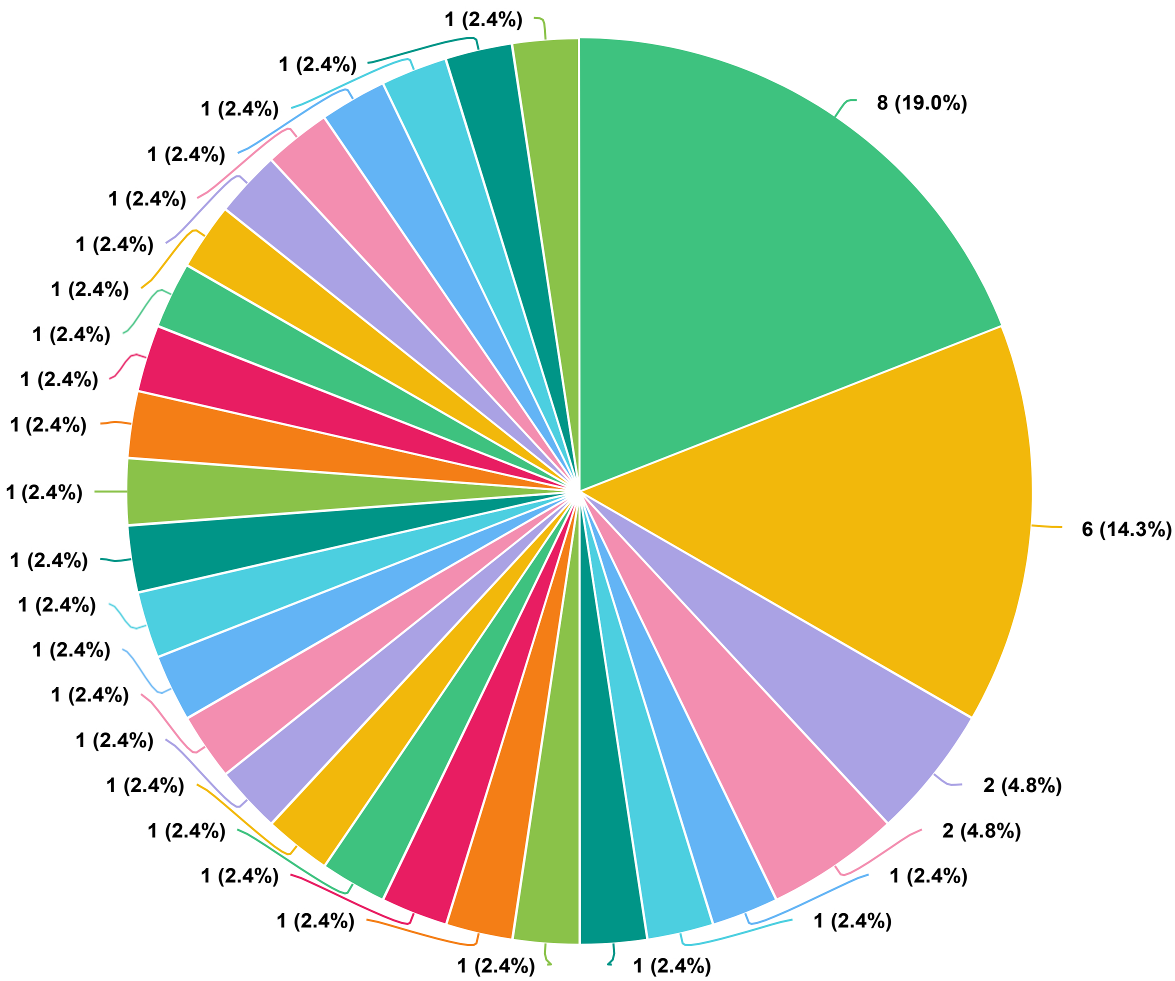


Question options

Thunder Bay, ON   Kenora, ON

Mandatory Question (309 response(s))
Question type: Radio Button Question

Q4 Please enter the first three digits of your Postal Code.

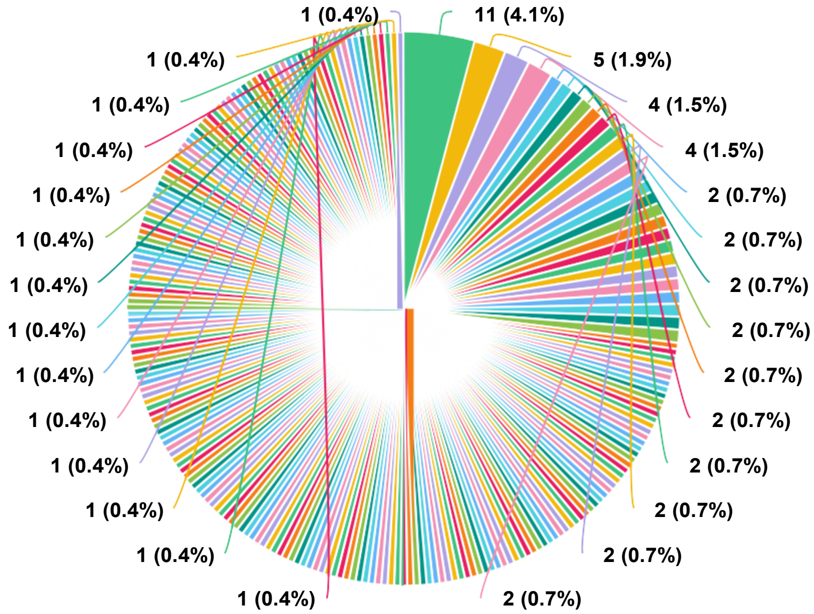


Question options

- Kenora, ON, P9N0J2
- Keewatin, ON, P0X0A1
- Kenora, ON, P9N0J5
- Kenora, ON, P9N4A4
- Kenora, ON, P9N1J5
- Kenora, ON, P9N0B2
- Kenora, ON, P9N3M9
- Kenora, ON, P9N3Y8
- Kenora, ON, P9N2C7
- Kenora, ON, P9N1H9
- Kenora, ON, P9N3A3
- Kenora, ON, P9N1K3
- Dalles, ON, P9N0J2
- Kenora, ON, P9N1Z3
- Kenora, ON, P9N2L2
- Kenora, ON, P9N2M8
- Kenora, ON, P9N2Y9
- Kenora, ON, P9N0B3
- Kenora, ON, P9N2K2
- Kenora, ON, P9N4P2
- Kenora, ON, P9N2H8
- Keewatin, ON, P0X1C0
- Kenora, ON, P9N1A5
- Kenora, ON, P9N1Y5
- Kenora, ON, P9N0A1
- Kenora, ON, P9N2S2
- Kenora, ON, P9N2K9
- Kenora, ON, P9N3C8

Mandatory Question (42 response(s))
Question type: Region Question

Q5 Please enter the first three digits of your Postal Code.



Question options

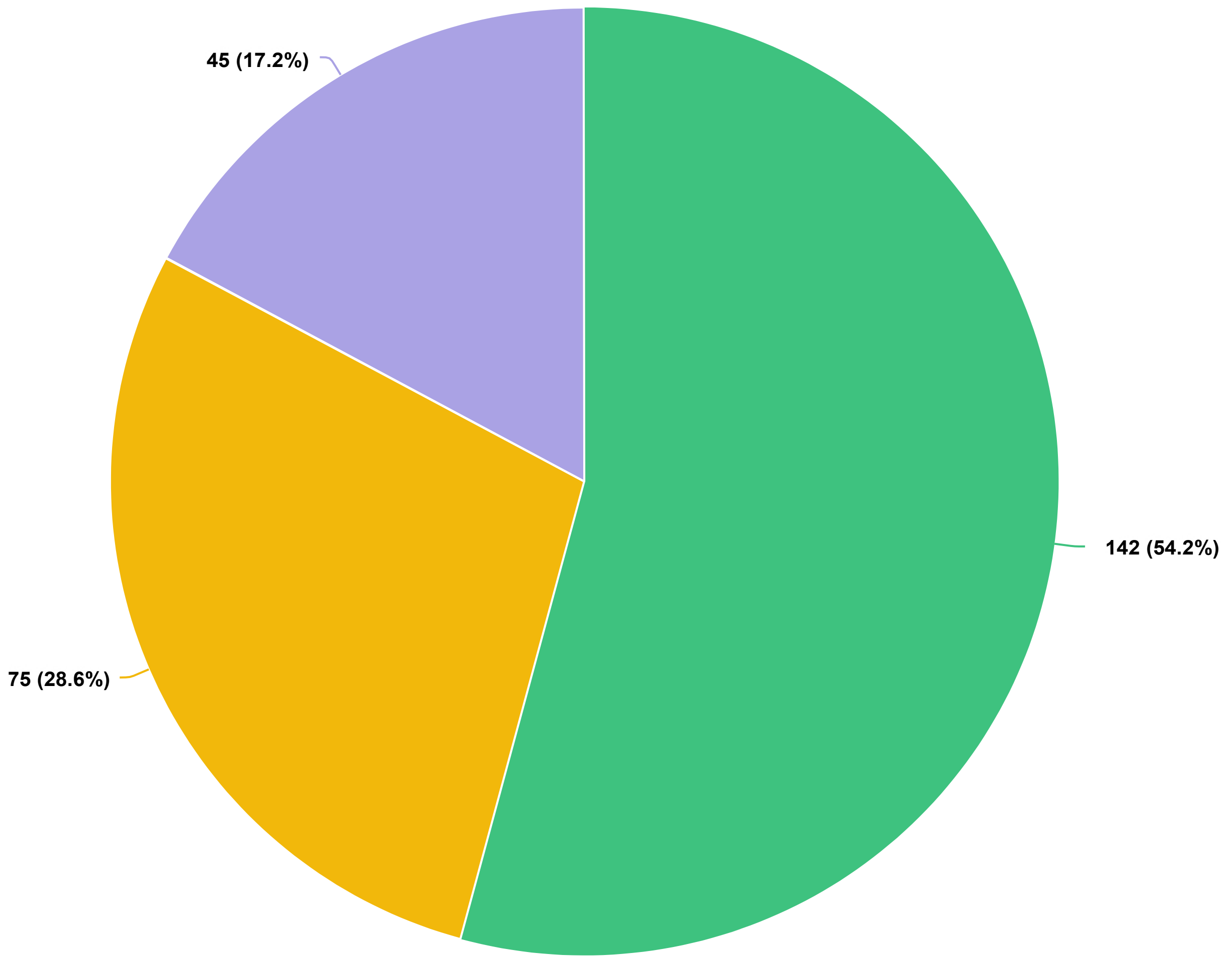
- Thunder Bay, ON, P7A7X4
- Thunder Bay, ON, P7B0C1
- Thunder Bay, ON, P7C0A8
- Thunder Bay, ON, P7E0A6
- Thunder Bay, ON, P7B3C4
- Thunder Bay, ON, P7C0B1
- Thunder Bay, ON, P7C5A9
- Thunder Bay, ON, P7K0V1
- Thunder Bay, ON, P7A8A1
- Thunder Bay, ON, P7K0V3
- Thunder Bay, ON, P7C1W1
- Thunder Bay, ON, P7E6T6
- Thunder Bay, ON, P7C4S8
- Thunder Bay, ON, P7B6Z7
- Thunder Bay, ON, P7A7T9
- Thunder Bay, ON, P7B5C7
- Thunder Bay, ON, P7B6G2
- Thunder Bay, ON, P7C1N6
- Thunder Bay, ON, P7G1V2
- Thunder Bay, ON, P7B5E3
- Thunder Bay, ON, P7G2J3
- Thunder Bay, ON, P7C2B3
- Thunder Bay, ON, P7C4M6
- Thunder Bay, ON, P7C1A3
- Thunder Bay, ON, P7C3E8
- Thunder Bay, ON, P7K1J9
- Thunder Bay, ON, P7G1N1
- Thunder Bay, ON, P7G2J1
- Thunder Bay, ON, P7A3P2
- Thunder Bay, ON, P7A3P5
- Thunder Bay, ON, P7B2B2
- Thunder Bay, ON, P7E5A4
- Thunder Bay, ON, P7E4P4
- Thunder Bay, ON, P7A2X9
- Thunder Bay, ON, P7A5Z7
- Thunder Bay, ON, P7E2E6
- Thunder Bay, ON, P7A5T1
- Thunder Bay, ON, P7A7P2
- Thunder Bay, ON, P7C1W5
- Thunder Bay, ON, P7A7Y7
- Thunder Bay, ON, P7B2L7
- Thunder Bay, ON, P7E5Z2
- Thunder Bay, ON, P7A7M4
- Thunder Bay, ON, P7E4B7
- Thunder Bay, ON, P7C4S4
- Thunder Bay, ON, P7C1R1
- Thunder Bay, ON, P7A7H8
- Thunder Bay, ON, P7C4G8
- Thunder Bay, ON, P7A1M9
- Thunder Bay, ON, P7B2E1
- Thunder Bay, ON, P7J1C3
- Thunder Bay, ON, P7A5H8
- Thunder Bay, ON, P7K1A2
- Thunder Bay, ON, P7A7Z9
- Thunder Bay, ON, P7G1T1
- Thunder Bay, ON, P7C2K3
- Thunder Bay, ON, P7E4A4
- Thunder Bay, ON, P7C3R7
- Thunder Bay, ON, P7E6M4
- Thunder Bay, ON, P7A4N1
- Thunder Bay, ON, P7E5N5
- Thunder Bay, ON, P7J1N5
- Thunder Bay, ON, P7E2T2
- Thunder Bay, ON, P7J1C1
- Thunder Bay, ON, P7K1L7
- Thunder Bay, ON, P7E4G2
- Thunder Bay, ON, P7A2T7
- Thunder Bay, ON, P7B6K7
- Thunder Bay, ON, P7C5B3
- Thunder Bay, ON, P7B4J2
- Thunder Bay, ON, P7A7S7
- Thunder Bay, ON, P7E4M2
- Thunder Bay, ON, P7C3L5
- Thunder Bay, ON, P7A6B4
- Thunder Bay, ON, P7E3X7
- Thunder Bay, ON, P7G1P4

1/4

Mandatory Question (267 response(s))
Question type: Region Question

THUNDER BAY

Q6 Vegetation Management SYNERGY NORTH must trim trees in proximity to overhead lines to avoid trees contacting lines for safety and reliability. Currently, SYNERGY NORTH trims trees reactively in our geographic regions to maintain safe clearances. Recently obtained aerial photography, has shown a requirement for an increase in spending to meet Canadian Safety standards required for tree trimming. These standards have been developed to ensure public safety in and around overhead lines. To meet these safety standards, an initial amount of trimming is required. This amount can be spread out from three (3) to seven years (7). Extending this project beyond seven years would affect SYNERGY NORTH's ability to maintain its operational safety and reliability standards. As a result of SYNERGY NORTH's 2022 survey, most customers supported the spending required to maintain these safe clearances and indicated a preference for spreading this spending over seven (7) years. The monthly impact of this is $1.24 per month on your electricity bill. Alternatively, this spending can be accelerated to three (3) or five (5) years with the following cost impacts: - The cost impact of spreading this spending over three (3) years is $2.89 per month on your electricity bill. The cost impact of spreading this spending over five (5) years is $2.07 per month on your electricity bill. Which of the following statements best represent your feelings on the expenses presented above?

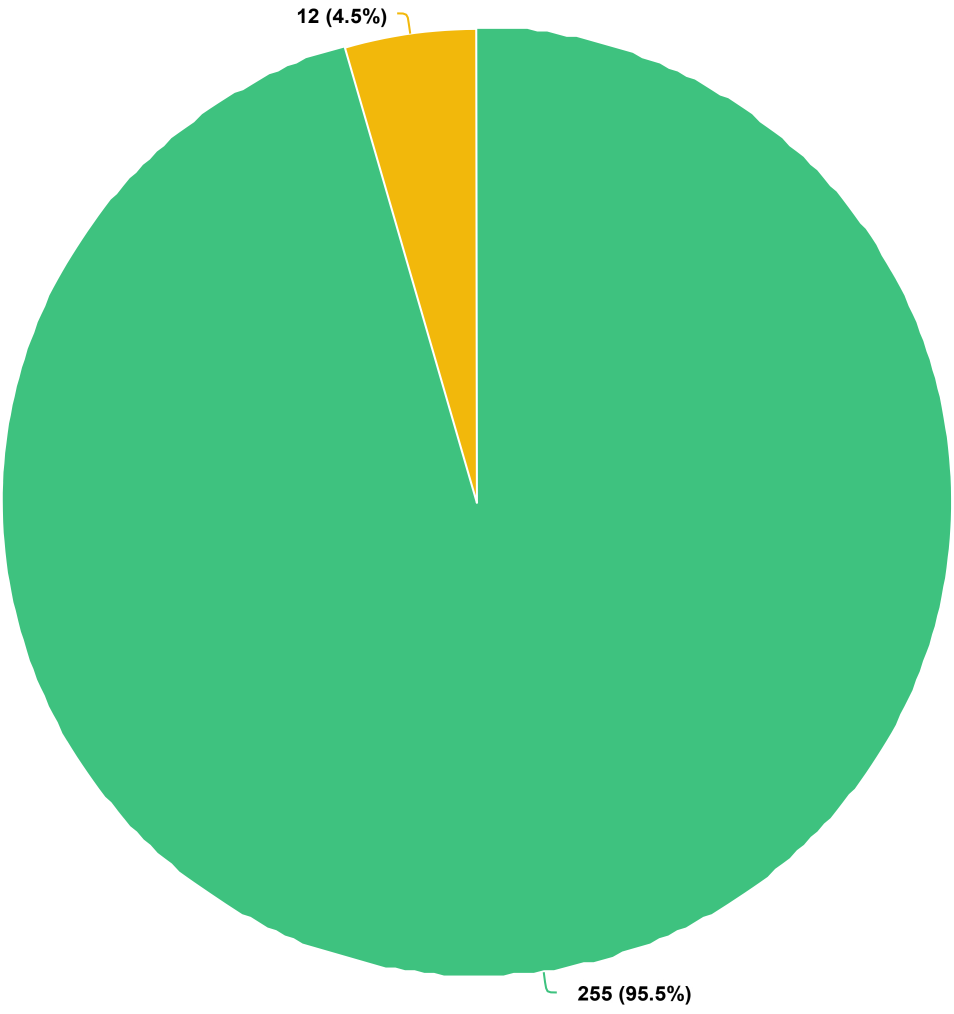


Question options

- Yes, I agree with spreading the tree trimming spending over seven (7) years
- I feel the spending should be accelerated to five (5) years
- I feel the spending should be accelerated to three (3) years

Optional question (262 response(s), 47 skipped)
Question type: Radio Button Question

Q7 Efficiencies - SYNERGY NORTH makes every effort to reduce the impacts of extra costs on customers through operational and management efficiencies. Examples of these types of efficiencies are the elimination of paper used in customer and billing processes, a reduction in leased office space, a reduction of staffing in several departments, converting customers to electronic billing, and other operational improvements. In addition, due to the merger between Kenora Hydro and Thunder Bay Hydro in 2019, cost savings have been realized due to efficiencies in administration and regulatory. In our previous survey, customers communicated that they are in favour of rate harmonization. Once, all SYNERGY NORTH customers are paying the same rate for their electricity distribution, more cost efficiencies will be realized from removing the added complexity of two rates zones. The rate impact of all these efficiencies results in a rate impact reduction of $1.44 per month. Which of the following statements best represent your understanding of the presented cost efficiencies?

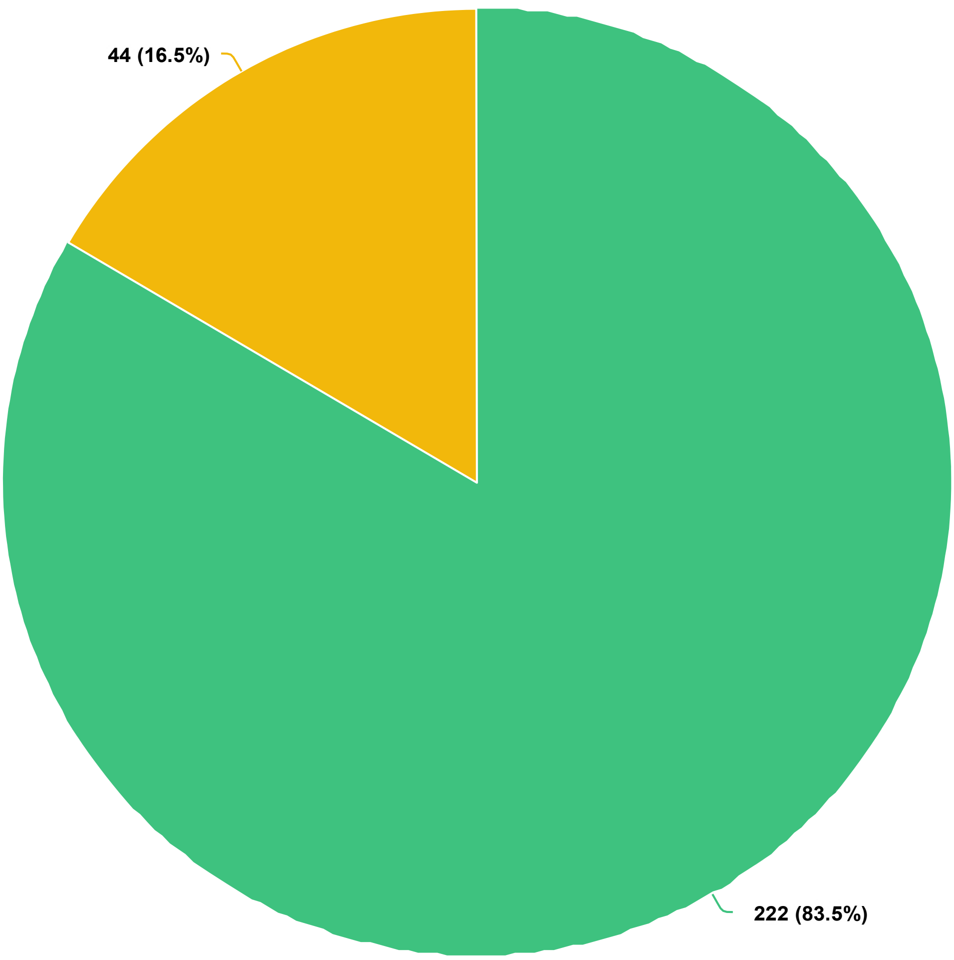


Question options

- Yes, I understand.
- No, I do not understand

Optional question (267 response(s), 42 skipped)
Question type: Radio Button Question

Q8 Commercial Funding Methodology - SYNERGY NORTH is required to obtain debt funding from commercial markets. This is a result of a decision of the majority shareholder to repay some of SYNERGY NORTH's outstanding debt and collect interest on the remaining portion. This interest will have a cost impact of $1.37 a month for customers on their electricity bill. Which of the following statements best represent your understanding of the presented costs of capital?

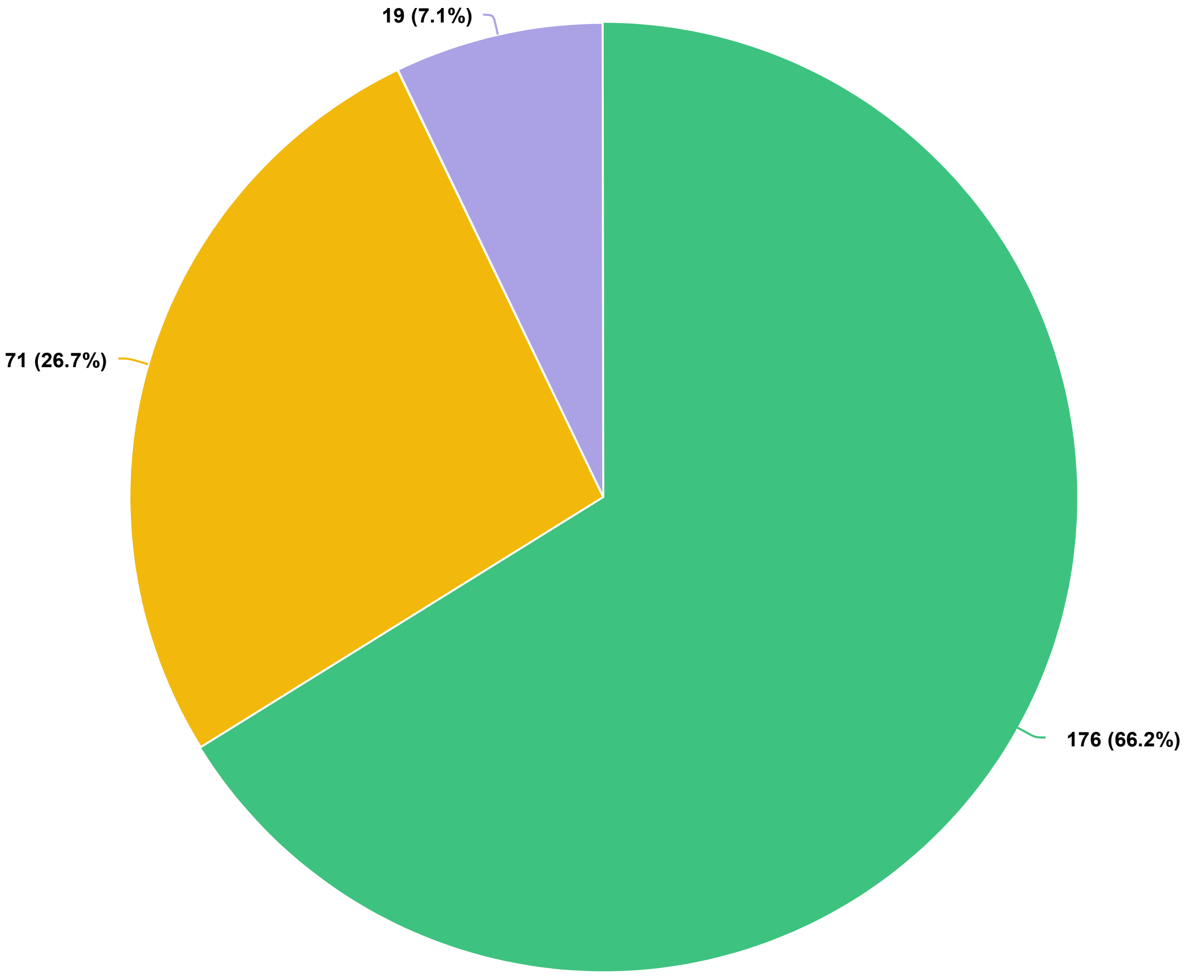


Question options

- Yes, I understand.
- No, I do not understand.

Optional question (266 response(s), 43 skipped)
Question type: Radio Button Question

Q9 Capital Plan - When surveyed, our customers have consistently expressed the desire to replace assets proactively rather than run them to failure. SYNERGY NORTH uses this philosophy to minimize the cost of new construction while maintaining the reliability our customers have come to expect. To achieve this SYNERGY NORTH maintains a Distribution System Plan (DSP) that is developed using risk based decision making for current assets and future development plans. This plan allows SYNERGY NORTH to appropriately defer investment in assets and schedule replacement based on condition rather than age. Further information about our DSP can be found here: DSP Learning Page The following presents our Capital Plan for the last and next five (5) years. The impact of SYNERGY NORTH's historical capital spending from 2017-2024, combined with the change in the Cost of Capital parameters on 2024 rates will create a rate increase of $2.64 per month in 2024. Beyond 2024, customers will see a yearly bill average increase of $0.60 per year over the life of the proposed capital investment plan (2024-2029). Without this investment, SYNERGY NORTH equipment will be at a greater risk for failure, affecting operations and reliability. Which of the following statements best represent understanding of the Capital Plan?

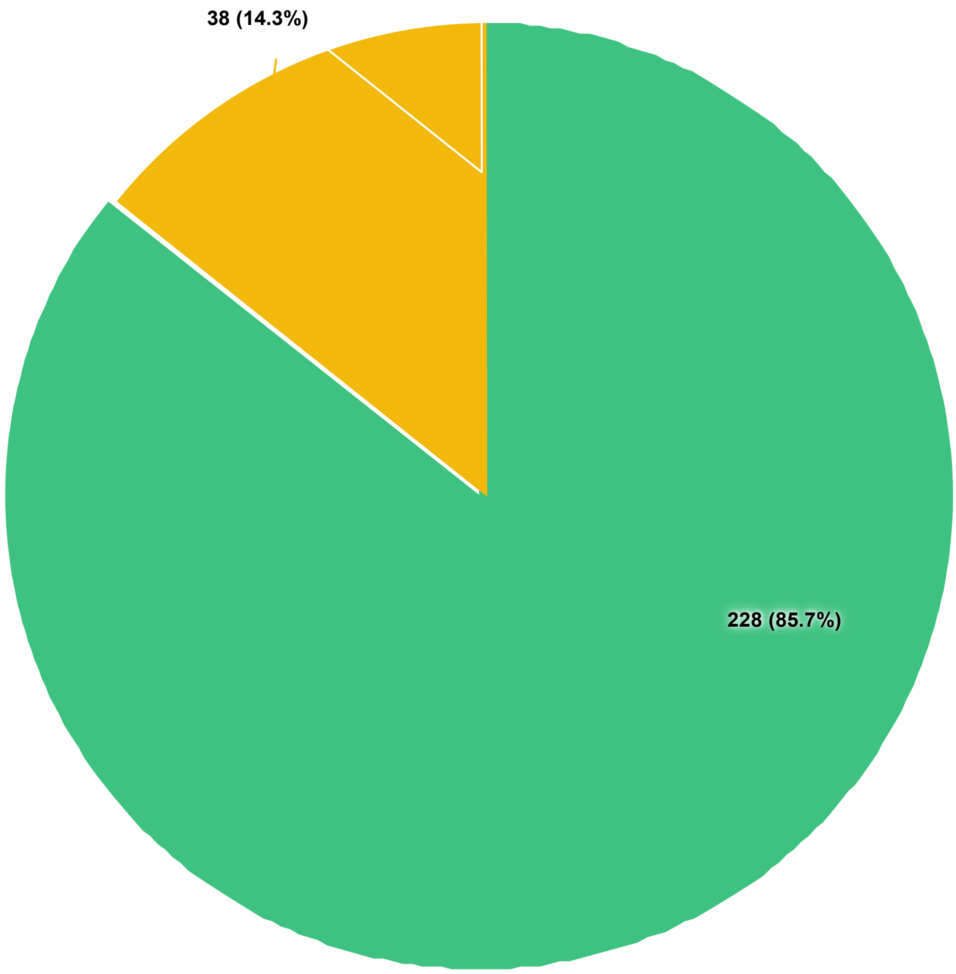


Question options

- Yes, I support a balanced capital spending plan.
- I do not support a balanced capital spending plan, but understand it is necessary.
- No, I do not support the capital spending plan as presented.

Optional question (266 response(s), 43 skipped)
Question type: Radio Button Question

Q10 Cost Allocation - SYNERGY NORTH undertakes a cost allocation process which is used to identify which portion of the utilities' costs should be applied to each class. SYNERGY NORTH saw a decrease in business customers in from 2017 to 2023. Also, residential customers have increased usage and customer count. Therefore, more of the cost is required to be allocated to the residential customers. This will result in a bill impact of $1.67 on a residential bill.Which of the following statements best represent your understanding of the presented cost allocation?

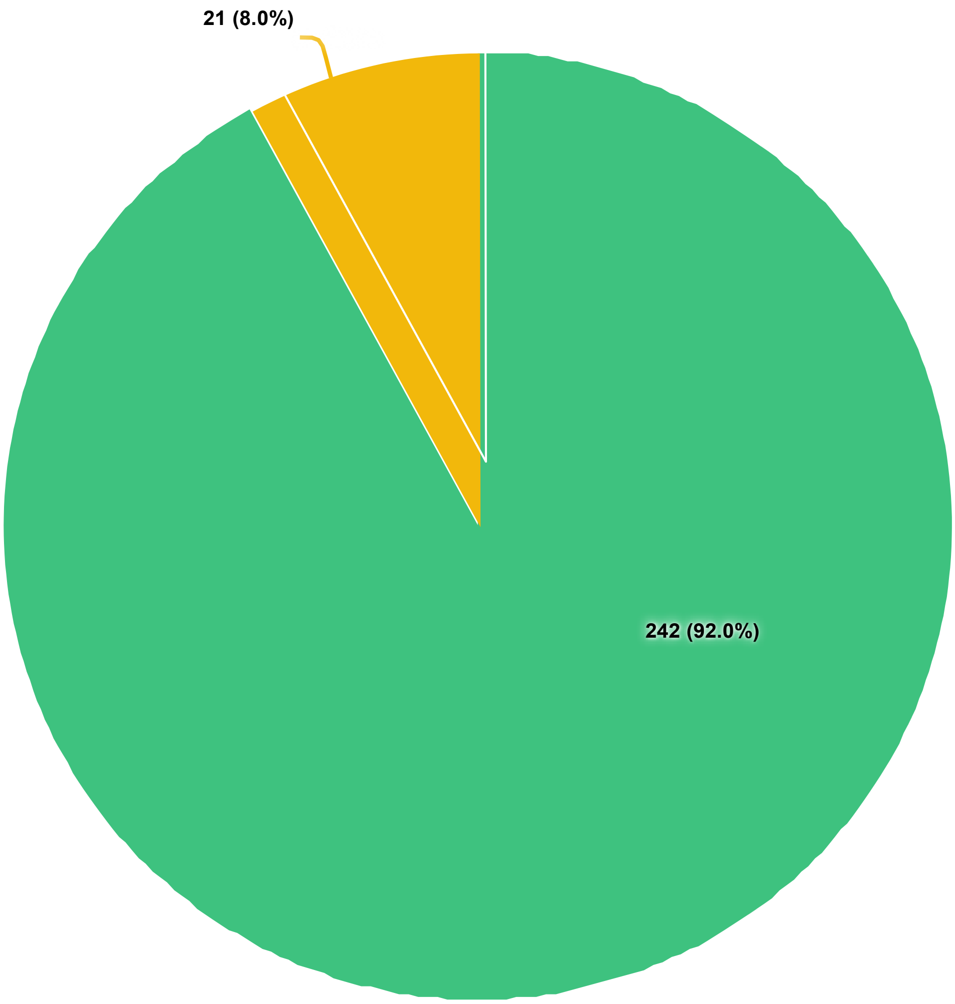


Question options

- Yes, I understand.
- No, I do not understand.

Optional question (266 response(s), 43 skipped)
Question type: Radio Button Question

Q11 Impact of Inflation - Inflation is significantly impacting the cost of SYNERGY NORTH's operations. For example, there has been a 33% increase in the price of gasoline costs impacting SYNERGY NORTH's fleet costs. Further, the costs of materials regularly used in neighbourhood projects have increased between 16% and 74%. The anticipated inflation on materials and operating costs will have an impact of $1.45 on our customers monthly electricity bill. Which of the following statements best represent your understanding of the presented cost pressures?

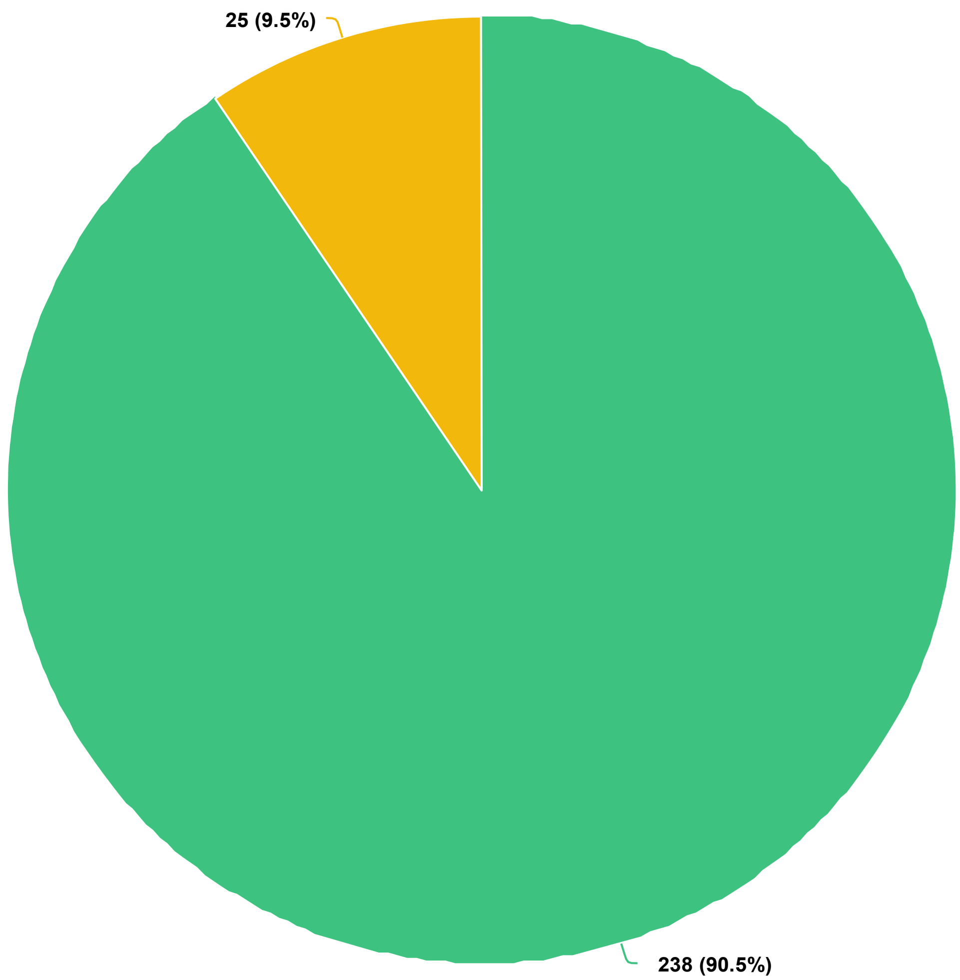


Question options

Yes, I understand. No, I do not understand.

Optional question (263 response(s), 46 skipped)
Question type: Radio Button Question

Q12 Other Cost Drivers - Like all electrical distribution companies in Ontario, SYNERGY NORTH is by the Ontario Energy Board (OEB). Cost increases due to regulatory requirements mandated by the OEB, such as the Green Button Initiative, Cyber Security, Cost of Service Application and Rate Harmonization costs will result in a monthly electricity bill increase of $0.70. Which of the following statements best represent your understanding of the proposed expenses presented above?

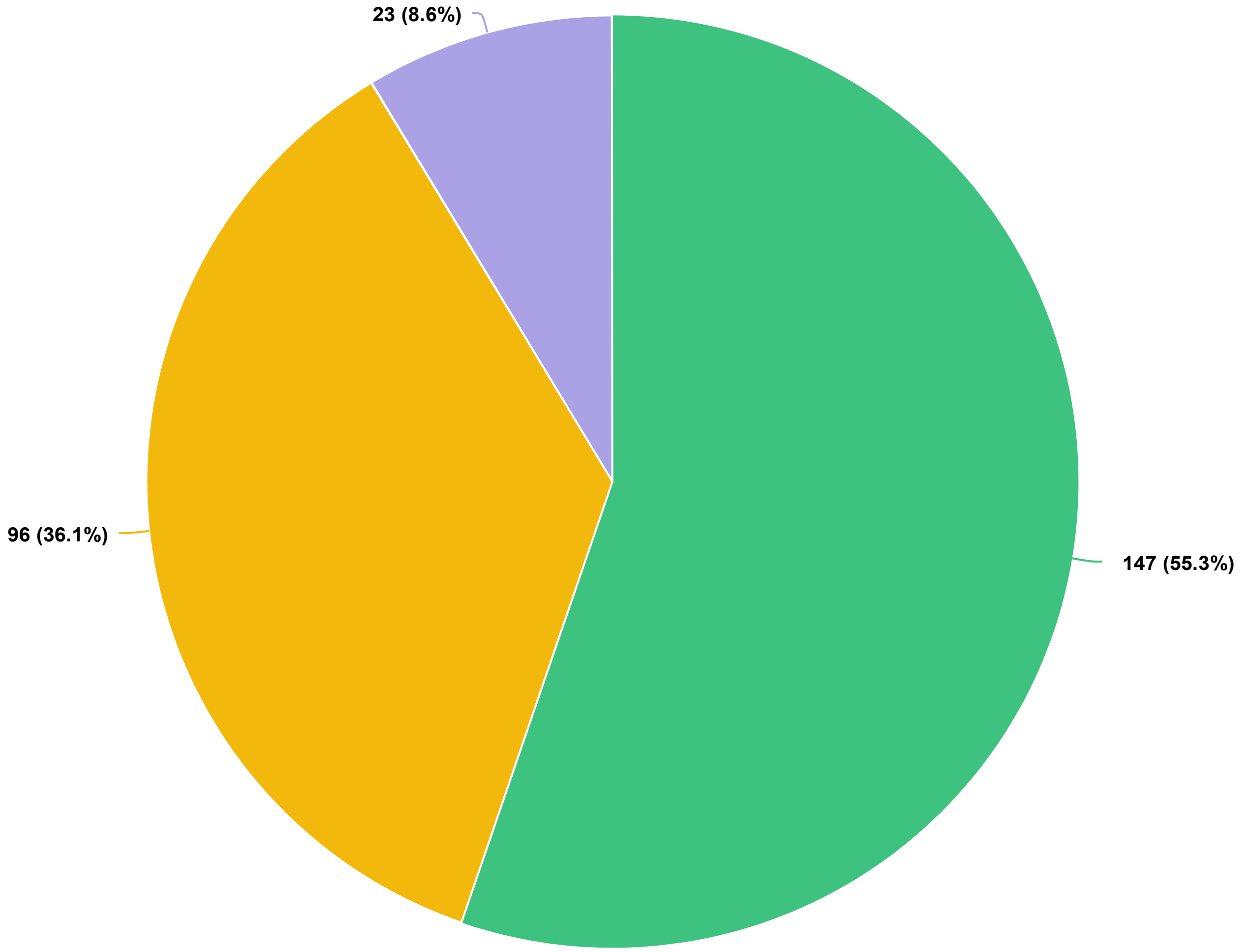


Question options

- Yes, I understand.
- No, I do not understand.

Optional question (263 response(s), 46 skipped)
Question type: Radio Button Question

Q13 **After having reviewed these cost drivers, what is your view on SYNERGY NORTH's Investment Plan as presented?**



Question options

- Yes, I support an Investment Plan which balances cost and reliability.
- I do not like the Investment Plan, but it appears necessary.
- No, I do not support the Investment Plan as presented.

Optional question (266 response(s), 43 skipped)
Question type: Radio Button Question

Q14 Please feel welcome to provide feedback on this engagement.

Anonymous 4/17/2023 04:59 PM	My biggest "beef" with the capital investment work is leaving old poles behind, some even with no other utilities attached. I now have two poles in my yard and I wish Synergy North would require Shaw to move its wires to the new pole so the old pole can be removed.
Anonymous 4/19/2023 12:03 PM	Thank you for your commitment to provide a balanced approach to spending. Warmest regards.
Anonymous 4/19/2023 07:12 PM	Sounds like a lot of increases to my bill, but you make it sound like it’s minimal because it’s spread out over multiple factors.
Anonymous 4/26/2023 07:54 AM	You are going to do what you want to anyway.
Anonymous 5/02/2023 08:44 AM	My biggest concern is moving cost from business to residential customers. Inflation and increased cost is much easier for businesses to manage over the long term rather than residential customers who, is some cases, don’t have the option to go to a traditional workplace post-COVID and the work from home movement by the same businesses as a means to cut cost and defer it to the employees. This move by Synergy will only increase this already significant burden on individuals.
Anonymous 5/02/2023 02:48 PM	I think there should be some sort of subsidies offered pending your tax bracket and income level. The middle class is being absolutely destroyed by the amount of taxes and additional fees we pay on every thing unfortunately.
Anonymous 5/03/2023 03:33 AM	I feel there can be cutbacks inside the business itself before passing on the increases to customers. ie The big uniform screw up with the name change, and going to a gas station that will give fleet fuel prices.
Anonymous 5/03/2023 08:11 AM	Any savings you can pass on to customers would be appreciated…,I also don’t think it’s fair to increase residential cost because business customers have declined .

Anonymous
5/03/2023 08:08 PM

With inflation and the cost of everything going up I'm not sure how many people will be able to afford to eat nevermind pay their hydro bill.

Anonymous
5/04/2023 08:26 AM

I understand that increases in cost, however in this survey it never discusses the profit Synergy has made over the years or even last fiscal.

Anonymous
5/04/2023 10:11 AM

There are many cost increasing factors and I am concerned about the overall financial impact

Anonymous
5/04/2023 08:59 PM

Why are customers paying to settle Synergy North's debt? That should come out of CEO and stakeholder profits.

Anonymous
5/05/2023 11:30 PM

What is the Green Button Initiative?

Anonymous
5/06/2023 03:50 PM

We pay enough. Better budgeting is the answer

Anonymous
5/06/2023 04:34 PM

Sucks that costs are going up…

Anonymous
5/06/2023 08:36 PM

There are many ways synergy spends my money that's I don't agree with, as example all the promotional videos done for what? No one sees them except your own staff when you rent out the movie theater and provide a very generous breakfast for the entire staff. Seems to be becoming a regular event. Feel free to contact me for more money saving ideas 6) although you may not like them.

Anonymous
5/07/2023 03:29 AM

Ontario has the most expensive hydro prices in all of Canada, and yet we have a surplus of energy that we get overcharged for. Everyone is still suffering from the pandemic and you still want to charge us more. We can't AFFORD IT!

Anonymous
5/08/2023 06:44 PM

thank you

Anonymous
5/09/2023 06:01 AM

I would rather ensure reliability of infrastructure than see an increase in outages or length of outages.

Anonymous 5/10/2023 05:55 PM	Too many increases when the cost of living is not increasing.
Anonymous 5/10/2023 07:36 PM	It was helpful
Anonymous 5/12/2023 11:25 AM	Thanks for the update
Anonymous 5/15/2023 10:12 AM	I agree with your plan to invest in infrastructure proactively.
Anonymous 5/15/2023 03:03 PM	I think capital plan savings need to be identified (some project deferrals, some run to failure for some equipment if spares are available) in view of the the effects of inflation and regulatory charge increases. I am ok with the increased risk this may cause . New neighborhood developers should pay more of the costs to bring power to new areas .
Anonymous 5/15/2023 06:59 PM	I support the plan and understand the need to pass this charge on to the customer but all neighbourhoods should benefit from this investment plan. There is aging infrastructure in our area and I have not seen any replacements to poles in the 17 years we've lived here and we experience outages more frequently due to trees. Trees have been trimmed but no aging infrastructure replaced that we've been made aware of.
Anonymous 5/16/2023 10:44 AM	How about using the stupid "Delivery Charge" to fund things? Any middle class family is struggling right now and adding to our bills is not helping. Take from your CEOs salary to fund any changes that are necessary. Help the community feed our families.
Anonymous 5/23/2023 06:50 PM	There are technical terms used which are not well explained. If you are expecting this survey to resonate with more people, you need to adjust the language, use more visuals, and use conventions people understand. In the finance table, number are presented 20,0000 .... 5,0000..... ? Why put four zeros after the comma? It throws the meaning of the table into question, which isn't good when it's millions of public dollars in question. I have tow university degrees and this survey doesn't present very clearly to me.

Anonymous
5/25/2023 07:16 AM

I value reliable electrical service, and am aware that in order to maintain reliability, money needs to be spent. I'm actually quite impressed by the reliability in the serving territory of Synergy North; whenever there is disruptive storm activity, the outages in this territory are few and far between, as opposed to other markets (as a result of my employment, I monitor the location of power outages to ensure uptime of our infrastructure). Keep doing what you're doing; as a ratepayer, I'm willing to spend a few extra bucks to make sure that my fridge stays cold, and my house stays warm.

Anonymous
5/26/2023 01:24 PM

keep up the good service

Anonymous
5/26/2023 03:33 PM

A reasonable plan in my opinion. With our increased wind storms I’m certainly in favour of more aggressive right of way maintenance. I might live downtown and be less impacted, but I see that as a cause of outages

Anonymous
6/01/2023 04:46 PM

Your vegetation management is a joke. You have tried to trim the trees on Fisher road multiple time but every time the wind blows or we have freezing rain the power goes out. Please have someone inspect this line and you will see the trees need a major trimming.

Anonymous
6/01/2023 06:11 PM

I really don’t like anything that has to raise the prices of our bills.

Anonymous
6/02/2023 04:42 AM

All utilities are way too costly especially for seniors

Anonymous
6/02/2023 11:47 AM

We all suffer from inflation & any increase on our monthly electric bill will affect our quality of life, especially seniors & low income families.

Anonymous
6/02/2023 07:53 PM

It appears with all these efficiencies the increase is substantial especially for seniors on fixed income.

Anonymous
6/03/2023 06:19 PM

Households are already burdened with the relative increases. However it is necessary for the sustainability of the utility.

Anonymous
6/06/2023 09:46 PM

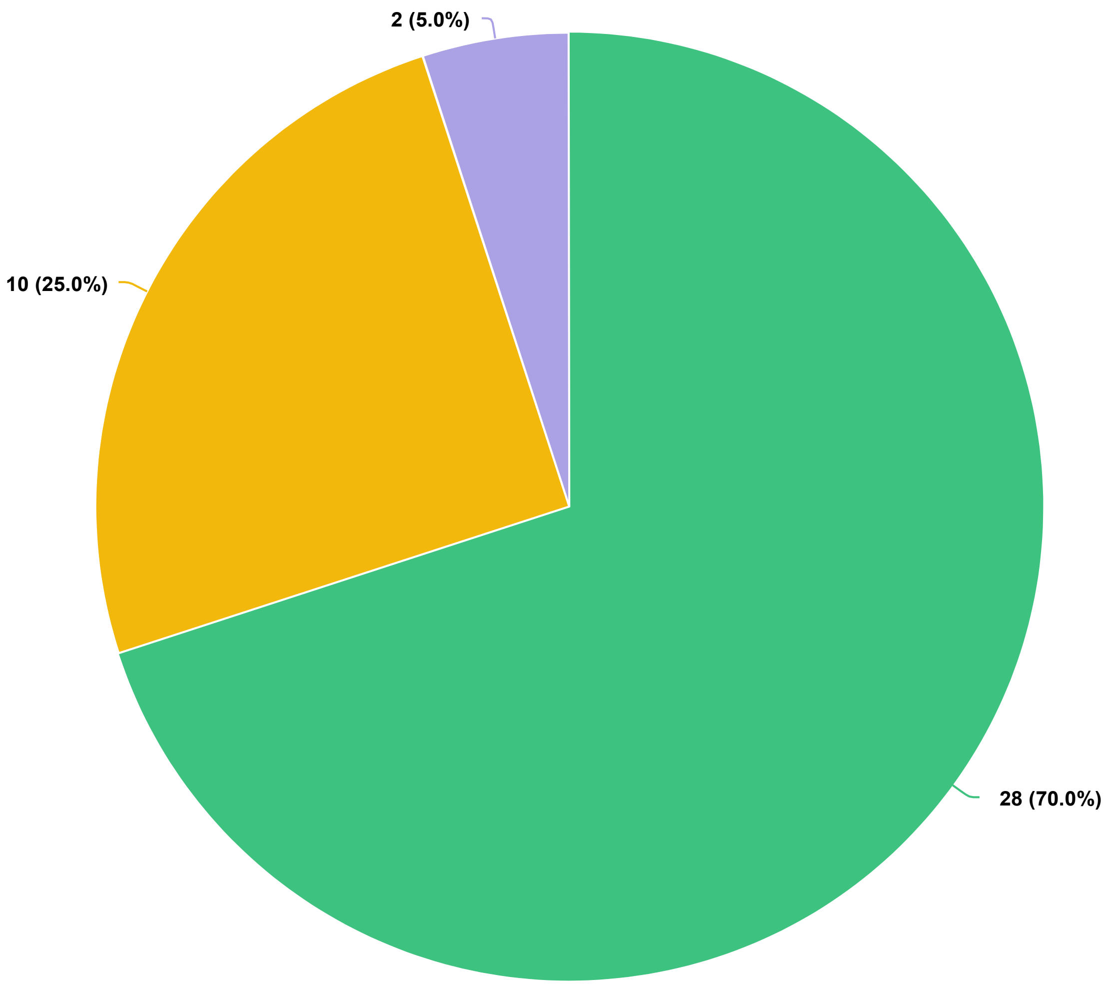
I need synergy North to tell me how I can save and be more efficient on my monthly bills. This is killing me

Anonymous 6/07/2023 08:06 AM	If funds were allocated from reducing bonuses from shareholders and upper management, including a 2% pay cut, this business plan could be better managed.
Anonymous 6/07/2023 08:16 AM	Please do your best the keep the companies cost down so customers are not impacted as much in the costs of electricity.
Anonymous 6/08/2023 10:08 AM	Reduce costs don't increase
Anonymous 6/09/2023 05:59 AM	I just can't afford all these utility increases.
Anonymous 6/09/2023 08:45 AM	Commercial customers should carry more of the burden of these increases.

Optional question (42 response(s), 267 skipped)
Question type: Essay Question

KENORA

Q15 Vegetation Management - SYNERGY NORTH must trim trees in proximity to overhead lines to avoid trees contacting lines for safety and reliability. Currently, SYNERGY NORTH trims trees reactively in our geographic regions to maintain safe clearances. Recently obtained aerial photography, has shown a requirement for an increase in spending to meet Canadian Safety standards required for tree trimming. The standards have been developed to ensure public safety in and around overhead lines. To meet these safety standards, an initial amount of trimming is required. This amount can be spread out from three (3) to seven years (7). Extending this project beyond seven years would affect SYNERGY NORTH's ability to maintain its operational safety and reliability standards. As a result of SYNERGY NORTH's 2022 survey, most customers supported the spending required to maintain these safe clearances and indicated a preference for spreading this spending over seven (7) years. The monthly impact of this is $1.24 per month on your electricity bill. Alternatively, this spending can be accelerated to three (3) or five (5) years with the following cost impacts: - The cost impact of spreading this spending over three (3) years is $2.89 per month on your electricity bill.- The cost impact of spreading this spending over five (5) years is $2.07 per month on your electricity bill. Which of the following statements best represent your feelings on the expenses presented above?

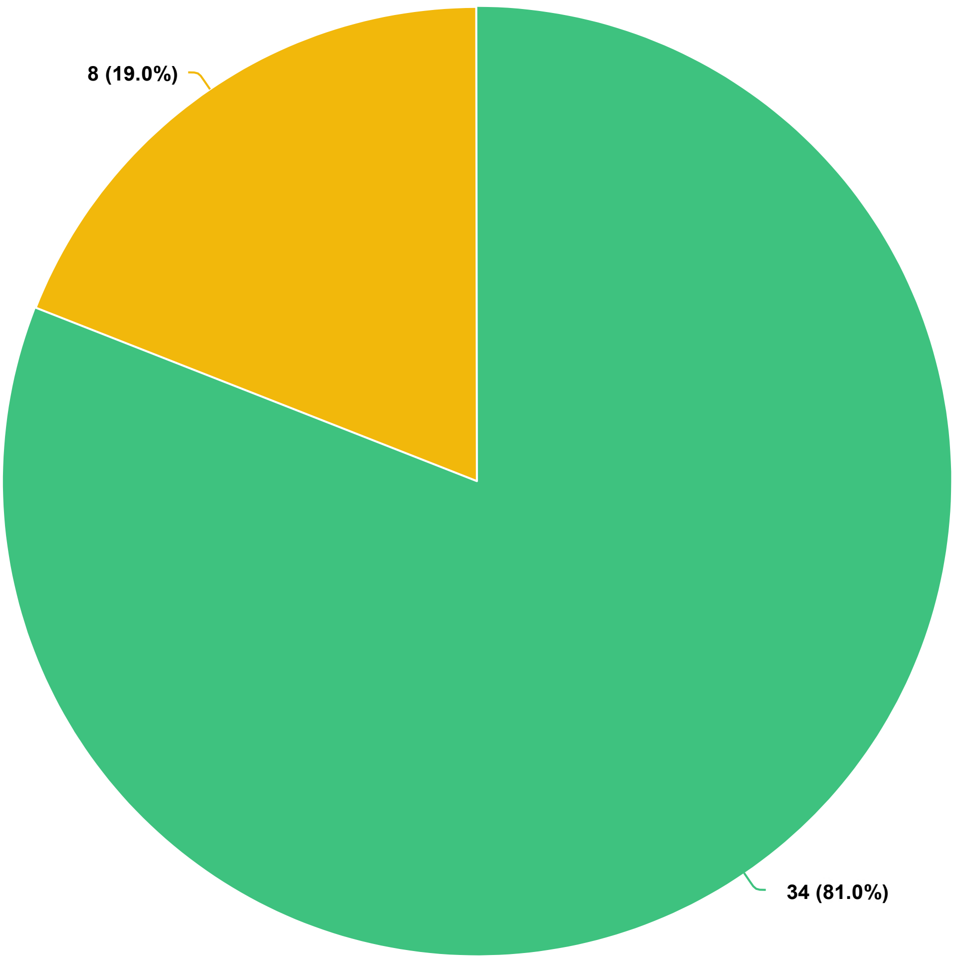


Question options

- Yes, I agree with spreading the tree trimming spending over seven (7) years.
- I feel the spending should be accelerated to five (5) years
- I feel the spending should be accelerated to three (3) years

Optional question (40 response(s), 269 skipped)
Question type: Radio Button Question

Q16 | Efficiencies - SYNERGY NORTH makes every effort to reduce the impacts of extra costs on customers through operational and management efficiencies. Examples of these types of efficiencies are the elimination of paper used in customer and billing processes, a reduction in leased office space, a reduction of staffing in several departments, converting customers to electronic billing, and other operational improvements. In addition, due to the merger between Kenora Hydro and Thunder Bay Hydro in 2019, cost savings have been realized due to efficiencies in administration and regulatory. In our previous survey, customers communicated that they are in favour of rate harmonization. Once, all SYNERGY NORTH customers are paying the same rate for their electricity distribution, more cost efficiencies will be realized from removing the added complexity of two rates zones. The rate impact of all these efficiencies results in a rate impact reduction of $1.44 per month. Which of the following statements best represent your understanding of the presented cost efficiencies?

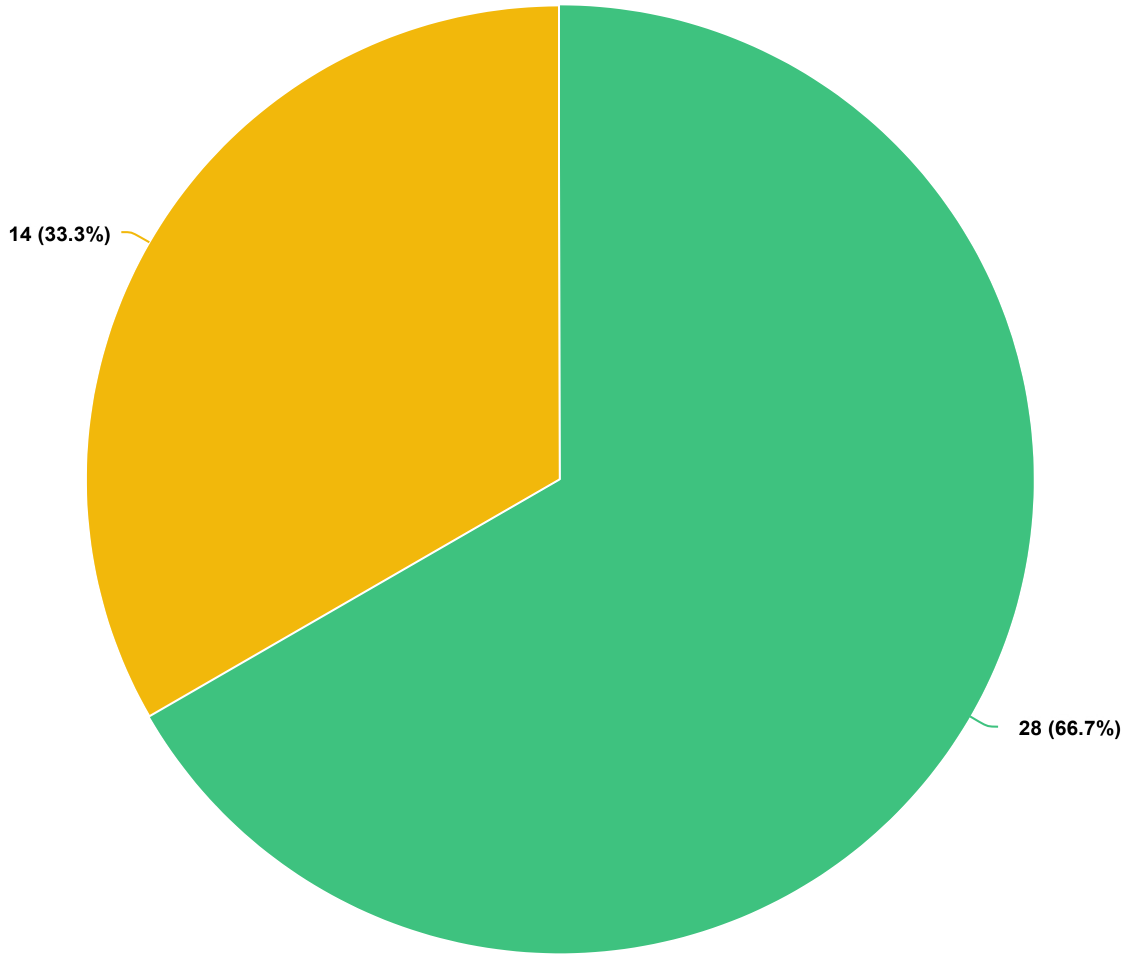


Question options

Yes, I understand. No, I do not understand

Optional question (42 response(s), 267 skipped)
Question type: Radio Button Question

Q17 Commercial Funding Methodology - SYNERGY NORTH is required to obtain debt funding from commercial markets. This is a result of a decision of the majority shareholder to repay some of SYNERGY NORTH's outstanding debt and collect interest on the remaining portion. This interest will have a cost impact of $1.37 a month for customers on their electricity bill. Which of the following statements best represent your understanding of the presented costs of capital?

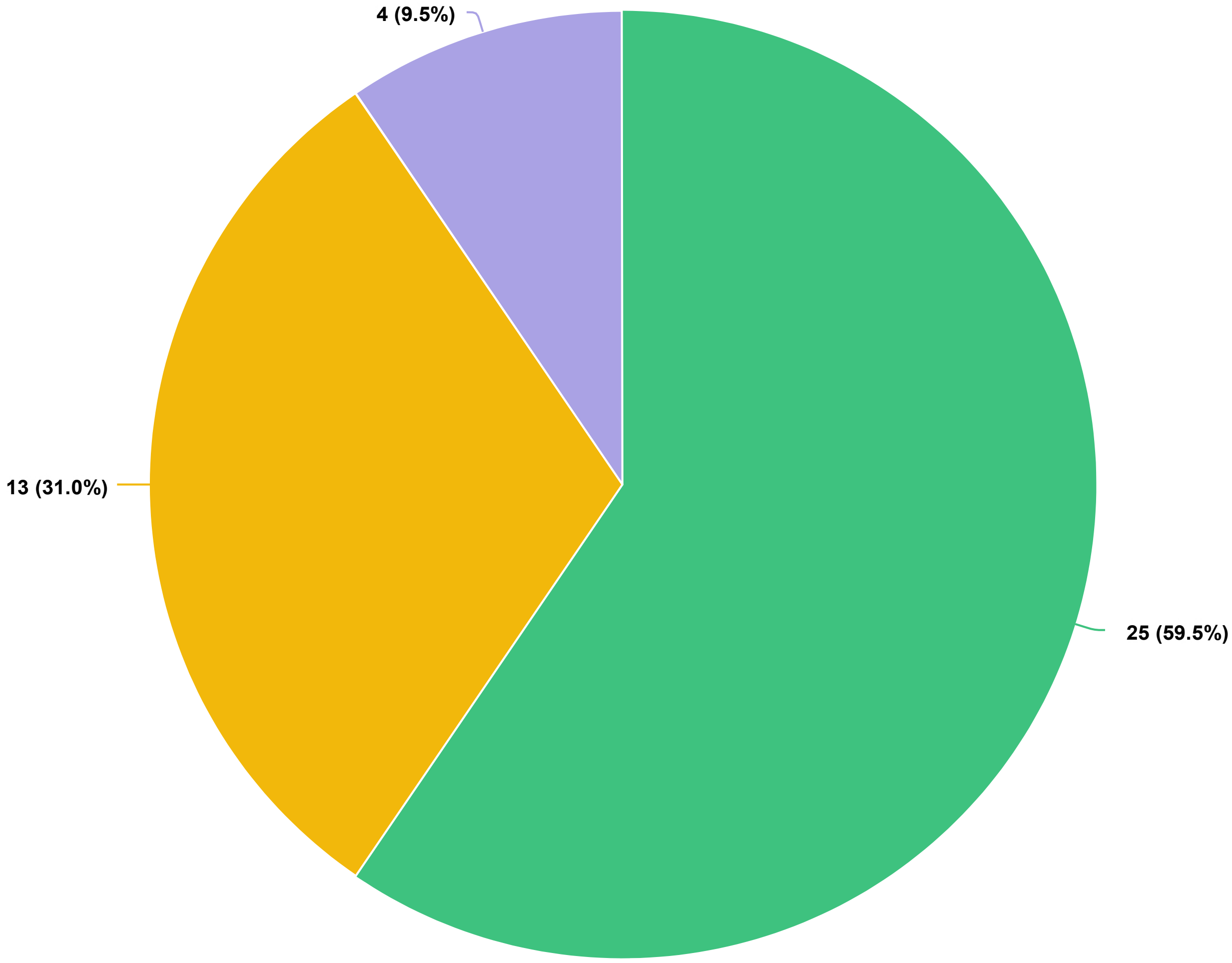


Question options

- Yes, I understand.
- No, I do not understand.

Optional question (42 response(s), 267 skipped)
Question type: Radio Button Question

Q18 **Capital Plan - When surveyed, our customers have consistently expressed the desire to replace assets proactively rather than run them to failure. SYNERGY NORTH uses this philosophy to minimize the cost of new construction while maintaining the reliability our customers have come to expect. To achieve this SYNERGY NORTH maintains a Distribution System Plan (DSP) that is developed using risk based decision making for current assets and future development plans. This plan allows SYNERGY NORTH to appropriately defer investment in assets and schedule replacement based on condition rather than age. The following presents our Capital Plan for the last and next five (5) years. The impact of SYNERGY NORTH's historical capital spending from 2017-2024, combined with the change in the Cost of Capital parameters on 2024 rates will create a rate increase of $0.22 per month in 2024. Beyond 2024, customers will see a yearly bill average increase of $0.60 per year over the life of the proposed capital investment plan (2024-2029). Without this investment, SYNERGY NORTH equipment will be at a greater risk for failure, affecting operations and reliability. Which of the following statements best represent understanding of the Capital Plan?**

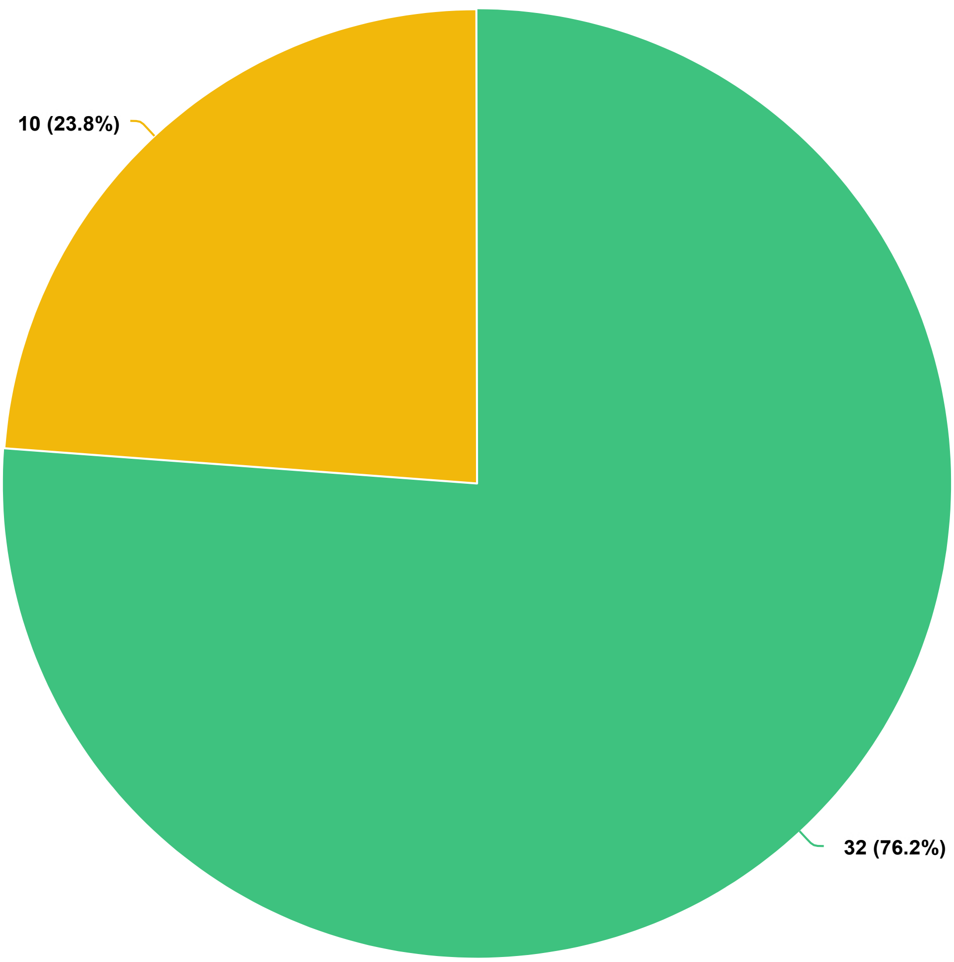


Question options

- Yes, I support a balanced capital spending plan.
- I do not support support a balanced capital spending plan. but understand it is necessary.
- No, I do not agree with the capital plan as presented.

Optional question (42 response(s), 267 skipped)
Question type: Radio Button Question

Q19 Cost Allocation - SYNERGY NORTH undertakes a cost allocation process which is used to identify which portion of the utilities' costs should be applied to each class. SYNERGY NORTH saw a decrease in business customers in from 2017 to 2023. Also, residential customers have increased usage and customer count. Therefore, more of the cost is required to be allocated to the residential customers. This will result in a bill impact of $2.24 on a residential bill. Which of the following statements best represent your understanding of the presented cost allocation?

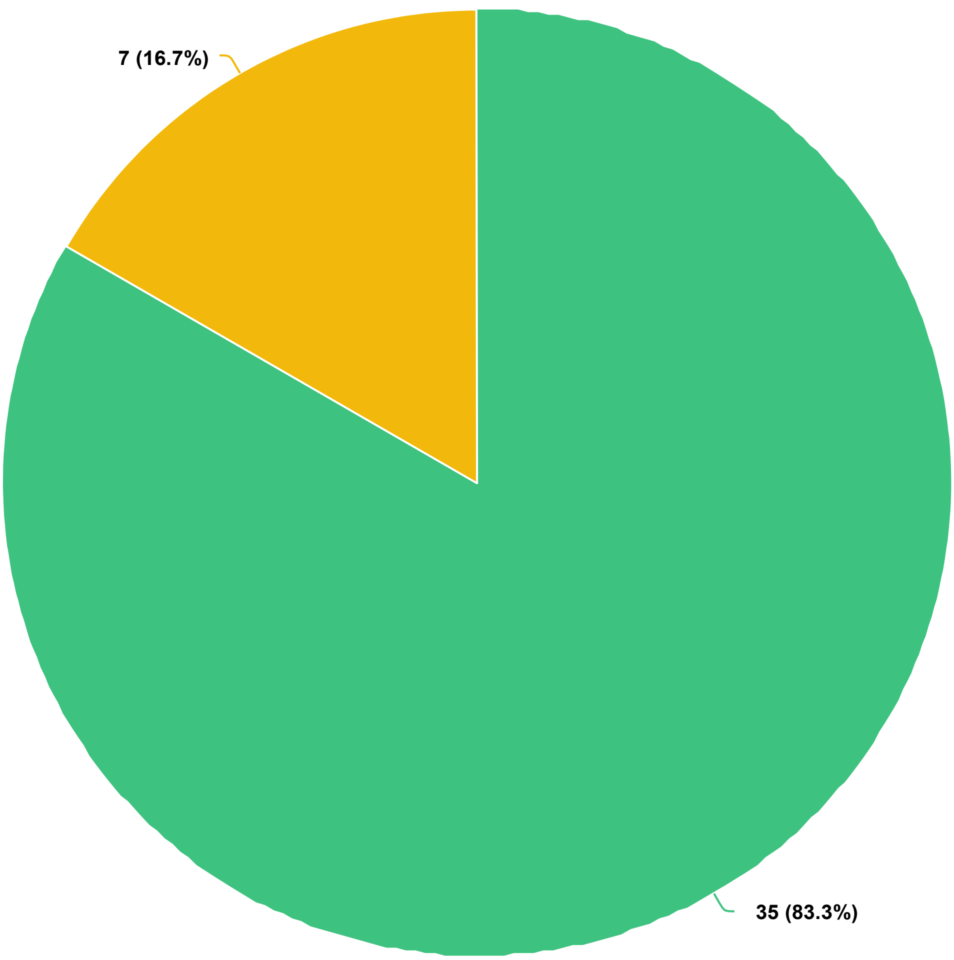


Question options

Yes, I understand. No, I do not understand.

Optional question (42 response(s), 267 skipped)
Question type: Radio Button Question

Q20 Impact of Inflation - Inflation is significantly impacting the cost of SYNERGY NORTH's operations. For example, there has been a 33% increase in the price of gasoline costs impacting SYNERGY NORTH's fleet costs. Further, the costs of materials regularly used in neighbourhood projects have increased between 16% and 74%. The anticipated inflation on materials and operating costs will have an impact of $1.87 on our customers monthly electricity bill. Which of the following statements best represent your understanding of the presented cost pressures?

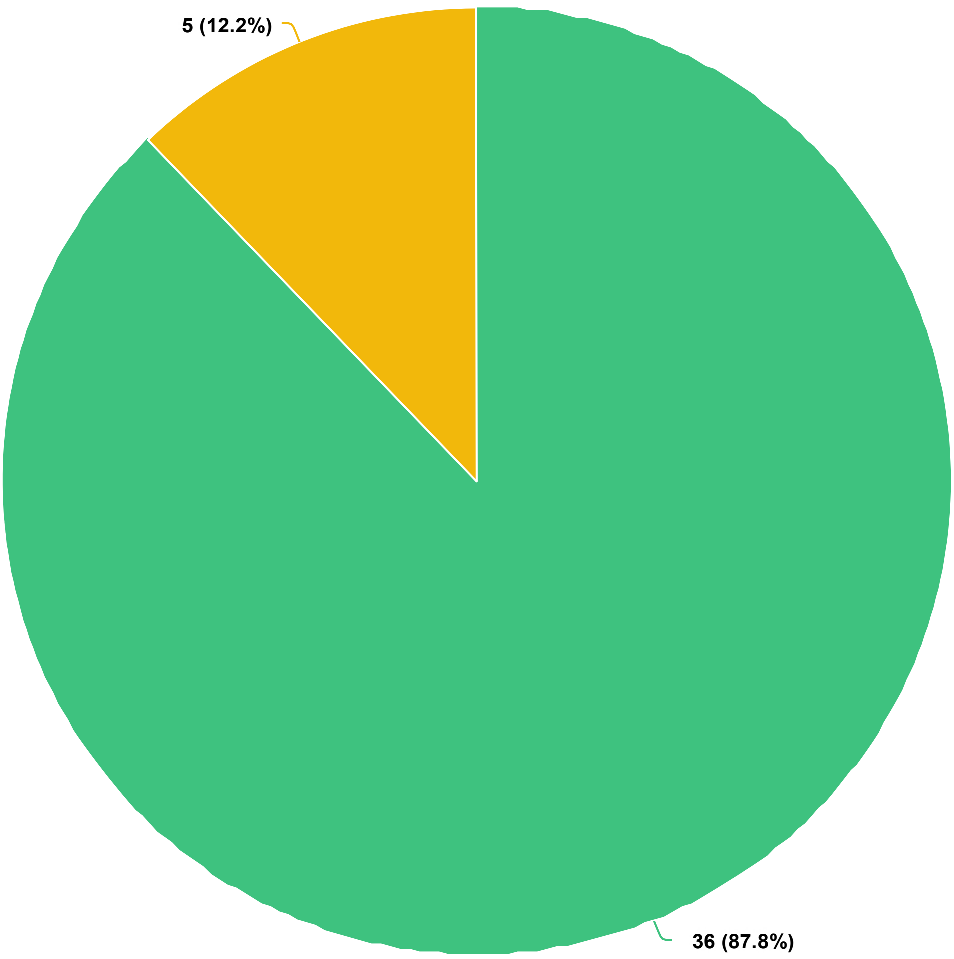


Question options

- Yes, I understand.
- No, I do not understand.

Optional question (42 response(s), 267 skipped)
Question type: Radio Button Question

Q21 | **Other Cost Drivers - Like all electrical distribution companies in Ontario, SYNERGY NORTH is regulated by the Ontario Energy Board (OEB). Cost increases due to regulatory requirements mandated by the OEB, such as the Green Button Initiative, Cyber Security, Cost of Service Application and Rate Harmonization costs will result in a monthly electricity bill decrease of $4.07. Which of the following statements best represent your understanding of the proposed expenses presented above?**

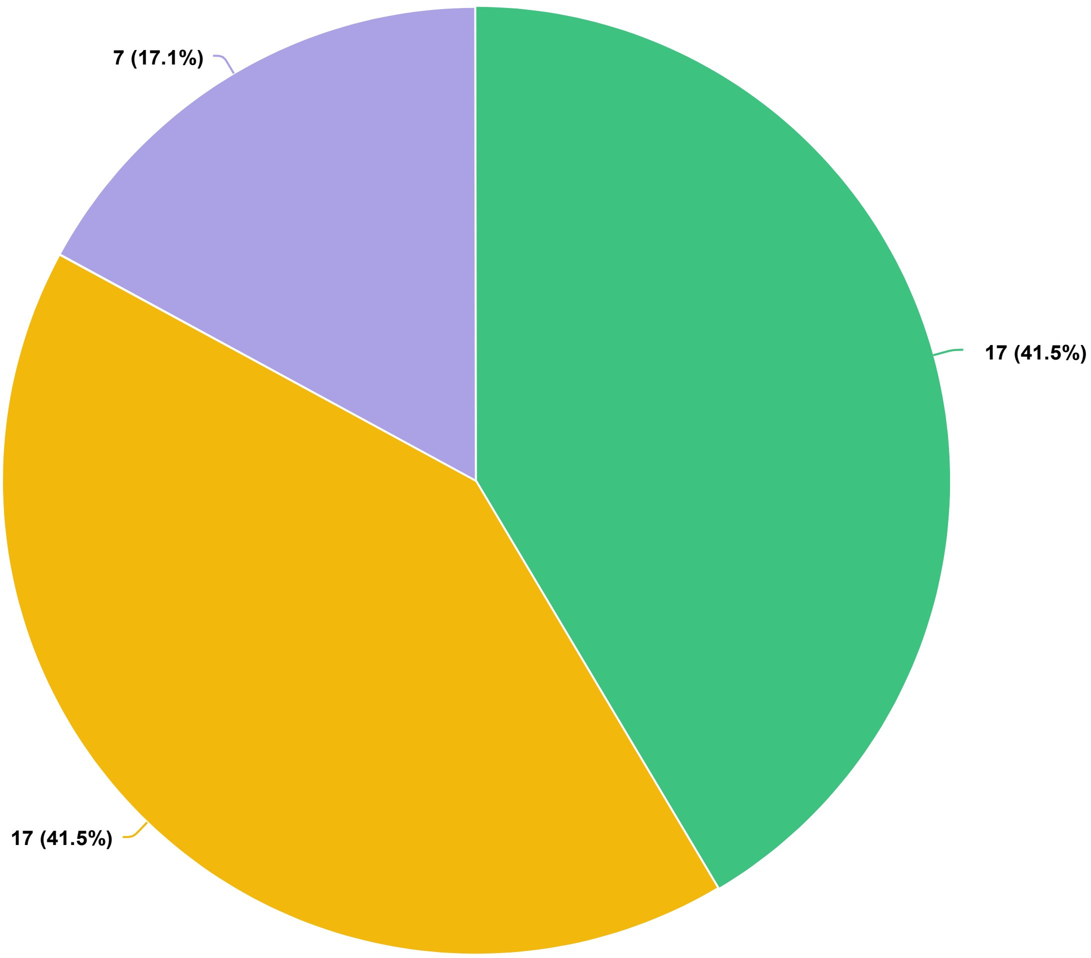


Question options

Yes, I understand.   No, I do not understand.

Optional question (41 response(s), 268 skipped)
Question type: Radio Button Question

Q22 **After having reviewed these cost drivers, what is your view on SYNERGY NORTH's Investment Plan as presented?**



Question options

- Yes, I support an Investment Plan which balances cost and reliability.
- I do not like the Investment Plan, but it appears necessary.
- No, I do not support the Investment Plan as presented.

Optional question (41 response(s), 268 skipped)
Question type: Radio Button Question

Q23 Please feel welcome to provide feedback on this engagement.

Anonymous
4/21/2023 04:14 PM

As a senior I have a fixed income so I either pay my electrical and heating bill and cut back on groceries and any upgrades to my house because I can't afford it.

Anonymous
4/21/2023 04:47 PM

Everything just costs more and more, and always gets downloaded onto customers. My salary doesn't increase, but everything else costs more and more.

Anonymous
4/22/2023 07:47 AM

You are a electricity provider, why does the fleet of vehicles consume gas? Roof top solar initiates needed.

Anonymous
4/26/2023 03:02 PM

IT IS IMPORTANT TO MAINTAIN A GOOD LEVEL OF SERVICE AND TO DO THIS EQUIPMENT MJUST BE MAINTAINED ALSO. i HAVE TRIED TO CONTACT SYNERGY FOR A POWER OUTAGE. YOUR SYSTEM FOR CALLING DOES NOT MAKE IT EASY TO REPORT. MAYBE REVIEW FOR A SIMPLER METHOD.

Anonymous
5/02/2023 01:42 PM

Do people really win these surveys?

Anonymous
5/03/2023 07:06 AM

A good company

Anonymous
5/07/2023 09:59 PM

While I understand that increases are necessary to meet the needs of electricity demand and that Synergy North is a reliable and reasonable provider, it is appreciated by customers that we have the opportunity to participate in surveys and receive reasonable rates.

Anonymous
5/08/2023 05:30 AM

Please stop falsely using the term ‘inflation’ and putting costs back onto users. Please start looking at profits and ways to support your communities and the people in them.

Anonymous
5/09/2023 07:05 PM

The survey really highlights that the cost is ultimately downloaded on the consumer and is death by one thousand cuts, it’s only 0.60 cents here and $1.37 here but it all adds up on already pressured people. How about some grants for people to invest in their homes there by reducing energy consumption. I am not talking about $75 off a smart meter, or the current one where you get $50 for a new door that costs $2000.00. I do not understand how people working minimum wage jobs even live. That said Synergy North has been great in Kenora and have always been excellent to work with.

Anonymous
5/11/2023 05:56 PM

With todays economic crisis, you think it is fair to people to raise the rates? Bad enough that the gas rates went up now this? Lots of people have to make a decision every month to either pay their utilities, rent or buy food for their families. Not everyone can do all 3 a month.

Anonymous
6/03/2023 06:27 AM

Times are tough right now, any added expense to anything is stressful. In our family we are mindful about the energy we are using to try to keep costs down.

Optional question (11 response(s), 298 skipped)
Question type: Essay Question

ATTACHMENT 1-6:

KMTS Survey

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DOCUMENT INFORMATION			
CLIENT	Synergy North	**DOCUMENT**	Report
PROJECT	Kenora MTS Substation Site Audit	**ITEM**	Site Audit Report
LOCATION	Kenora, ON	**DOCUMENT NO.**	18075-02-R-9000
PROJECT NUMBER	18075-02	**REVISION**	0

INTERNAL APPROVAL STATUS			
STATUS	**NAME**	**SIGNATURE**	**DATE (DD/MMM/YY)**
PREPARED BY	Michael Zachary	MJZ	15-Aug-19
REVIEWED BY	Jay Kruzliak, Tim Ricard	JFK,TJR	15-Aug-19
APPROVED BY	Jay Kruzliak	JFK	15-Aug-19

CLIENT REVIEW STATUS			
STATUS	**NAME**	**SIGNATURE**	**DATE (DD/MMM/YY)**
REVIEWED BY			
REVIEWED BY			

REVISION STATUS		
REVISION	**DESCRIPTION**	**DATE (DD/MMM/YY)**
0	Final Report	15-Nov-19

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TABLE OF CONTENTS

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TABLE OF APPENDICES

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1 Scope of Work and Objectives

The scope of work and objectives are summarized as follows:

- Visual inspection of existing conditions at Kenora MTS which includes but is not limited to;
  - Substation grounding and bonding integrity
  - Condition assessment of existing medium voltage switchgear
  - Condition assessment of existing substation power transformers
  - Collection of vertical clearance measurements
  - Collection of field measurements as may be required for potential future substation modifications
- Ground grid analysis and testing using the Fall of Potential method

In addition to the physical site inspection, supplementary information for this report was obtained from Synergy North, including a summary of previous equipment tests completed on Kenora MTS.

2 Revision Summary

Revision A: July 2019 (Nordmin Project #18075-02)

- Initial Draft release

3 Executive Summary

Nordmin Engineering Ltd. was retained by Synergy North to perform an inspection on the recently-acquired Kenora Hydro Substation located in Kenora, Ontario. The purpose of the inspection was to:

- Visually inspect the state of the existing switchgear and transformers located in the substation
- Evaluate the state of the existing grounding and existing clearances located in the substation
- Provide recommendations for improvement to allow the facility to continue to operate safely and effectively

A site visit was conducted by two Nordmin personnel on July 8 and 9, 2019 (Jay Kruzliak, P.Eng., senior electrical engineer and Michael Zachary, EIT). This report details their findings and provides recommendations to ensure the safe operation of the substation. Below is a summary of the findings and proposed recommendations.

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Switchgear

- The remaining useful life of the switchgear is estimated at 8-10 years, meaning Switchgear 1 and 2 should be replaced by that time.

- Switchgear 1 and 2 both had water ingress into their respective pull pits and Switchgear cells. This should be dealt with immediately by sealing all joints of the switchgear along with conduits entering the pull pits. A foam or Sikaflex type sealant would be best. The Switchgear cells should also be gasketed on top of each cubicle and all the way around. The use of an industrial sump pump would also be beneficial to drain the water when it becomes excessive. A permanent solution would be to direct bore a drainpipe from the slope adjacent to the roadway into the bottom of the pull pits. The water in the pull pits and leaking into the Switchgear is creating severe humidity within the gear which will eventually lead to failure.

- Switchgear 1 and 2 had corrosion present at most joints on the bus bar. This should be dealt with immediately by removing, wire-wheeling (cleaning) and re-torqueing all bus connections. Failure to clean the bus could lead to a potential arc flash incident or excessive bus heating causing a failure.

- There was no fusing present in either feeder section of the Switchgear. This should be dealt with immediately by inserting fusing in place of the solid blades.

- The tie switch cell in Switchgear 2 was removed due to multiple lightning strikes. The switchgear cell had burn marks on the inside of the door. This and other areas of the switchgear where rust is present should be cleaned and repainted immediately to help identify future arcing, corrosion, leaking and other issues. It is also advisable to insert a new tie switch in the long term, to be able to implement a load sharing option in an emergency situation.

- The insulation on the CT wires in feeder A-L of Switchgear 2 are extremely frayed and disintegrating. This should be dealt with immediately by replacing all CT wires inside feeder A-L. Failure to repair the wiring could result in an open CT condition which result in a catastrophic failure of the CT(s).

- Switchgear 1 and 2 share a common ground bus through the Switchgear. The ground bus is only grounded at one end in Switchgear T1. A second ground bus should be added from the station ground electrode to the Switchgear T2 ground bus for safety in the short term.

- The Switchgear and Substation in general should be inspected yearly. The switchgear should be de-energized and all bus, joints, insulators and switches cleaned during this inspection.

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Transformers

- Transformers T1, T2 and T4 have no oil containment areas. This should be dealt with in the short term to prevent potential environmental damage and costly cleanup if an oil spill occurs. A curb around each transformer along with a Sorbweb type material (imbiber material) for a containment pad would be most cost effective.

- The liquid temperature of Transformer T4 was running hot (60^{o} C). Three radiator valves on the east side were in the closed position but Nordmin was informed that they were in-fact open. It should be immediately confirmed which position these valves are in, and if in the closed position, it is advisable that they be opened to allow for greater circulation of oil, which will lower the liquid temperature of the transformer. Overheating will negatively impact the life of the transformer.

- Transformer T3 has had various parts removed within the control cabinet. If this unit is to be a viable spare in the future, the missing parts should be acquired and re-installed, the winding and oil temperature gauges should be replaced, and the porcelain insulators inspected.

- The Transformers should be inspected and tested yearly to ensure there is no damage to the windings, leaking oil, temperature issues etc. that could cause premature failure.

Recloser and Switch Poles

- Some recloser and switch poles had no grounding mesh mats installed. All poles should have mesh mats installed under each switch before operation of said switch. Every switch and non-energized metal bracket should also be grounded. This should be completed in the long term. This is imperative for worker safety.

Perimeter Fence

- There were various areas of the fence that were not tied together or had large openings present. This should be dealt with immediately by properly tying together or blocking off these areas to ensure to unwanted entry.

- All broken crossmembers, tension wires and fabric ties should be fixed and replaced immediately.

- The side fence that connects the east side of the perimeter fence to the substation fence is not isolated. This should be dealt with immediately by inserting a wooden fenced section to isolate both areas. Another option would be to properly ground the un-isolated section as per OESC. This is imperative to protect the workers and public from possible shock hazards.

- There were areas along the perimeter of the fence where the ground wire was visible. This should be dealt with in the short term by burying the ground wire and covering with rock.

- All ungrounded areas such as bared wire and corner tie posts should be grounded in the short term. Grounding is a key safety element in the substation.

Miscellaneous

- The Kirk Key system in the substation does not stop Switchgear 1 and 2 from being operated while the primary switch is closed. Although the switches in each Switchgear are load break switches, THEY SHOULD NOT BE OPERATED while the primary switch is closed due to the age and moisture within the gear. It is recommended that in the short term a Kirk Key be added to the primary side of the transformers to ensure that the primary switch be open before any work can be done within the Switchgear. A 3-cylinder transfer interlock block could be implemented to ensure that the feeders are isolated before the primary disconnect switches are operated. A similar system should be installed on Switch 4 to achieve a similar switching procedure. It is recommended that this be completed in the long run, to ensure that the Switchgear switches are not operated unless the primary switch is closed.

- Each feeder pole has ceramic lightning arrestors. These are prone to cracking and chipping, so it is important they be kept clean and regularly inspected. In the long term it is advisable to replace these with polymer lightning arrestors. Failure of the arrestors will prevent adequate protection during a lightning strike.

- Overhead T1 and T2, glass string insulators were present. These are prone to cracking and chipping. These string insulators are in close proximity to Transformer T1 and T2 bushings and if chipping or cracking occurs, they could cause damage to the transformers and transformer bushings. This should be dealt with immediately by replacing the glass string insulators with polymer before failure occurs. Polymer insulators are lighter, stronger, less prone to vibration, more tolerant of pollution and do not fail catastrophically.

- Overhead T1 and T2 has porcelain insulators on the switches and stand off insulators. These are prone to cracking and chipping and should be cleaned and inspected regularly. In the long term it is advisable to replace these insulators with polymer insulators before failure occurs.

- The area behind Transformer T2 is sectioned off due to the falling debris of the old T3 structure. This should be dealt with immediately by removing the insulators, switches and equipment from the old T3 structure. Full tension splices would need to be completed so that the insulators and structure could be removed due to the fact that the incoming line to T2 is spliced just before the structure and the substation insulators are still being used on the structure to support the line. This is an immediate hazard for workers in the substation.

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Low Cost Repairs

There are several low-cost repairs that can be completed immediately, including:

- Fence grounding, fabric repair, tension wire and fence coupling repair
- Grounding within the substation yard (exposed loops etc.)
- Cleaning Switchgear thoroughly, painting and re-sealing Switchgear

Maintenance

Regular maintenance (yearly) inspections should be performed for all switchgear, transformers and overhead equipment to identify any issues before failure occurs and yearly oil sampling of the transformers to ensure there are no internal issues. Resealing of the switchgear should be done at this time with cleaning of the bus as the level of corrosion dictates.

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4 Detailed Equipment Review

The following subsections describe any specific issues that Nordmin observed with the equipment in the substation directly. The recommended improvements that could be made to improve safety and reliability of the existing equipment are summarized in Section 5.0.

Where applicable, photos are included to illustrate the issues within the scope of work.

4.1 Switchgear 1 (B1-BUS)

Figure 4-1 – Switchgear 1 (B1-BUS)

Figure 4-1 depicts Switchgear 1 (B1-BUS) and cable pull pit. The cable pull pit and entrance into the switchgear was filled with water. Figure 4-2A depicts the water inside the pull pit and Figure 4-2B depicts the water in the pull pit, below the Switchgear (there was water present in both Feeder B-L and Feeder C-L). A sump pump hose was present in the pull pit, but the original sump pump installed could not keep up with the amount of water entering the foundation. Water appears to be entering by various points including around the switchgear cells through the gaskets, from the unsealed conduits to the feeder poles and around the base of the switchgear. The persistent moisture within the switchgear has caused significant corrosion on the exposed bus, degraded some of the internal cell wiring and creates a high moisture environment within the gear.

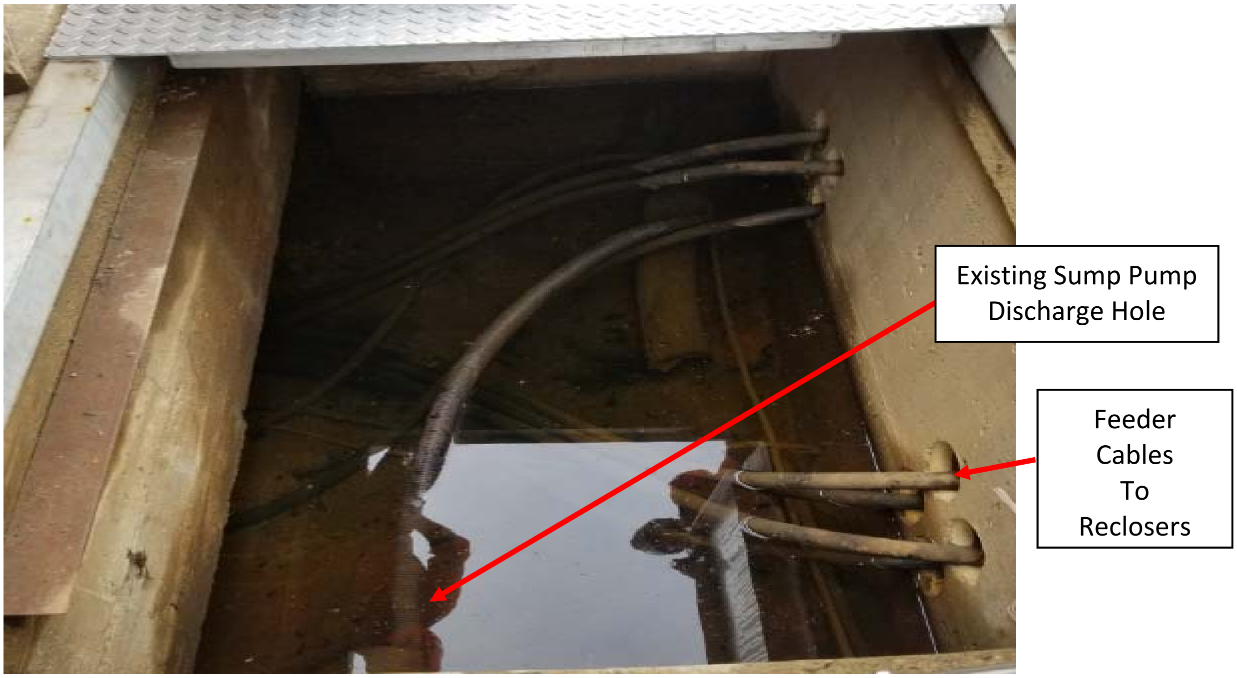

Figure 4-2A – Cable Pull Pit

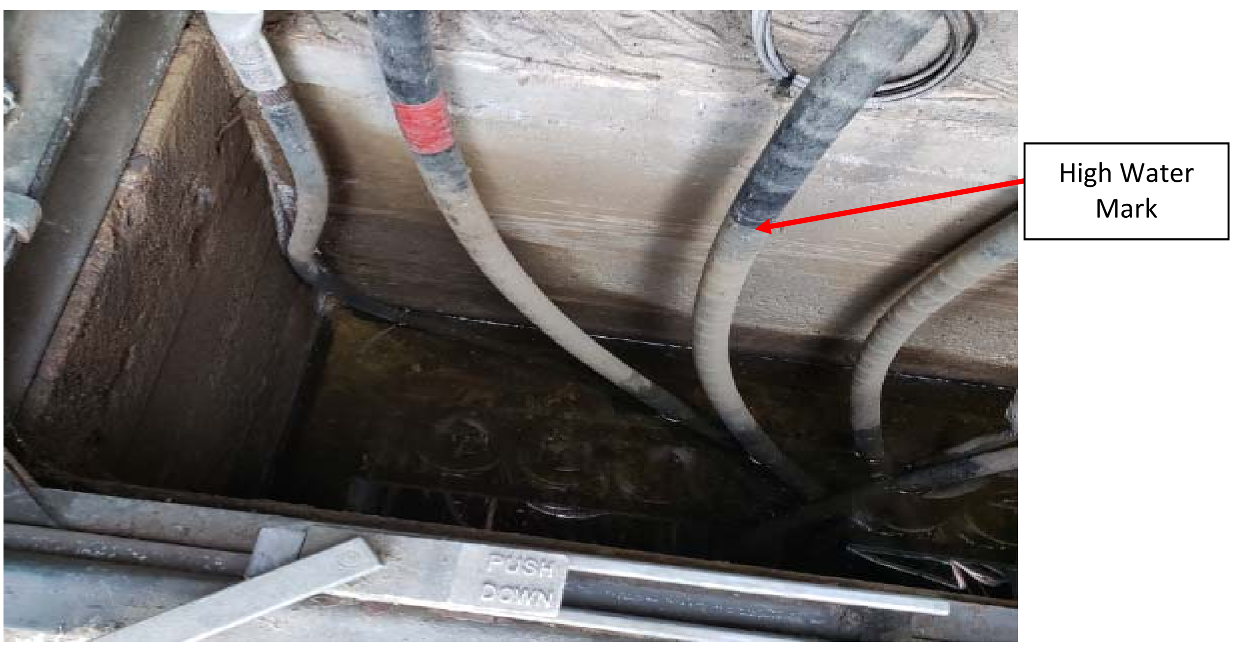

Figure 4-2B – Cable Pull Pit Inside Switchgear

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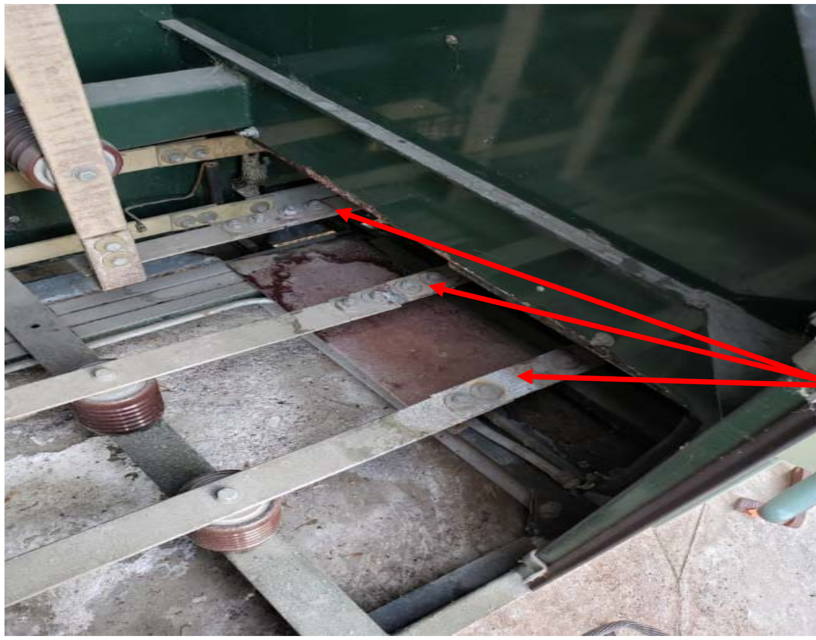

Figure 4-3 – T1-B1

Figure 4-3 depicts the rust and corrosion inside the T1-B1 cell of Switchgear 1. There are multiple areas affected by corrosion on the bus and at all joints in the bus bar. Areas of the switchgear metal cladding are also rusting due to the high moisture.

Figure 4-4 – Top of Switchgear

Figure 4-4 depicts an area at the top of Switchgear 1 that has a broken seal. Many sites along the top and sides of the switchgear have degraded seals and should be resealed to ensure that there is no water leakage into any of the cells.

Figure 4-5 – Switchgear to TX-1 connection

Figure 4-5 depicts the switchgear to TX-1 connection. A missing bolt is present in the lower right corner of the panel.

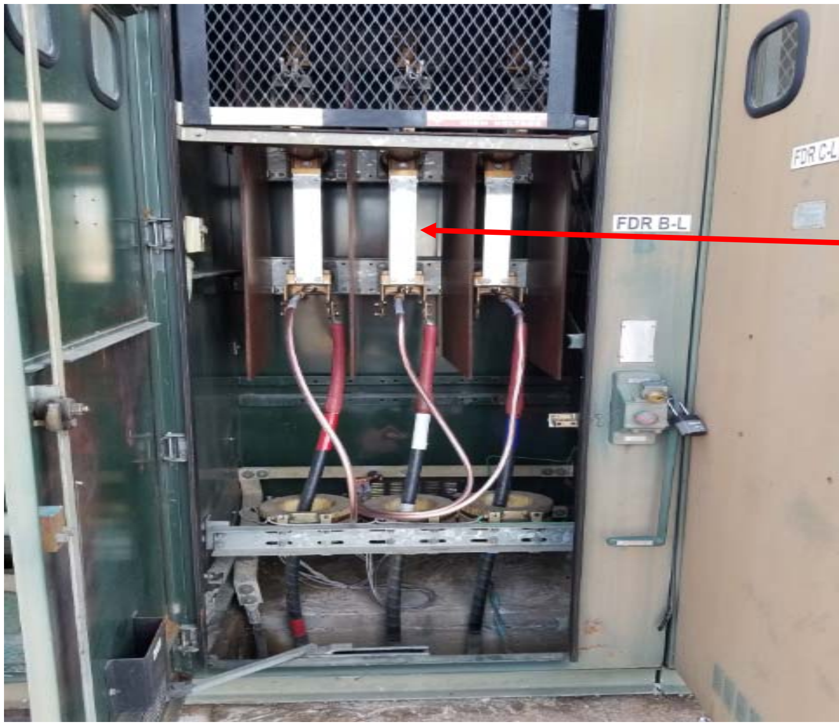

Figure 4-6 – Feeder B-L

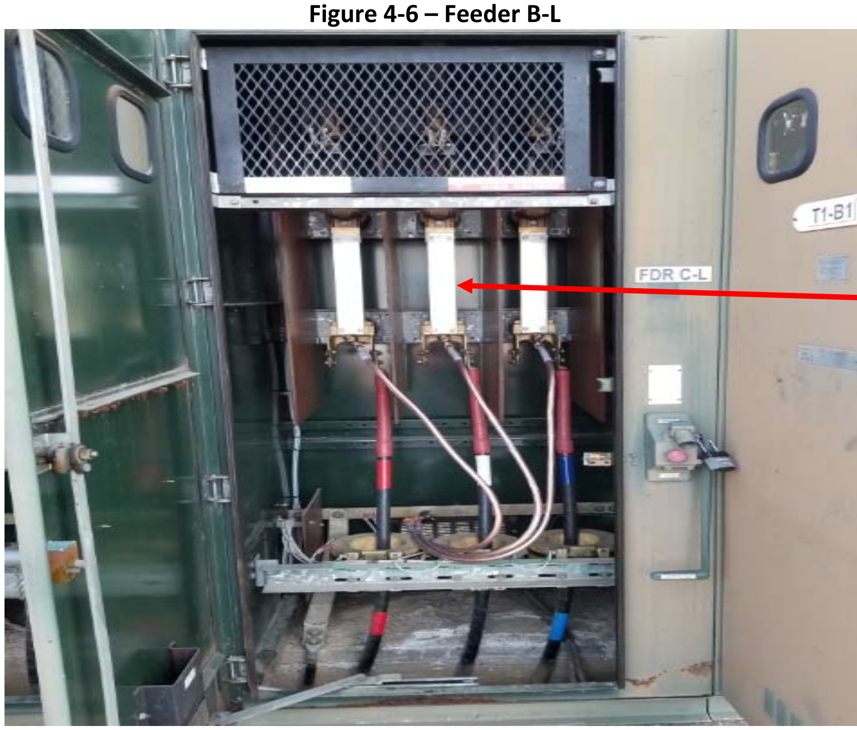

Figure 4-7 – Feeder C-L

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Figure 4-6 and 4-7 depict the areas with no fusing inside Feeder B-L and Feeder C-L of the switchgear. It is Nordmin's understanding that there is already a plan in motion to replace fusing in the cells.

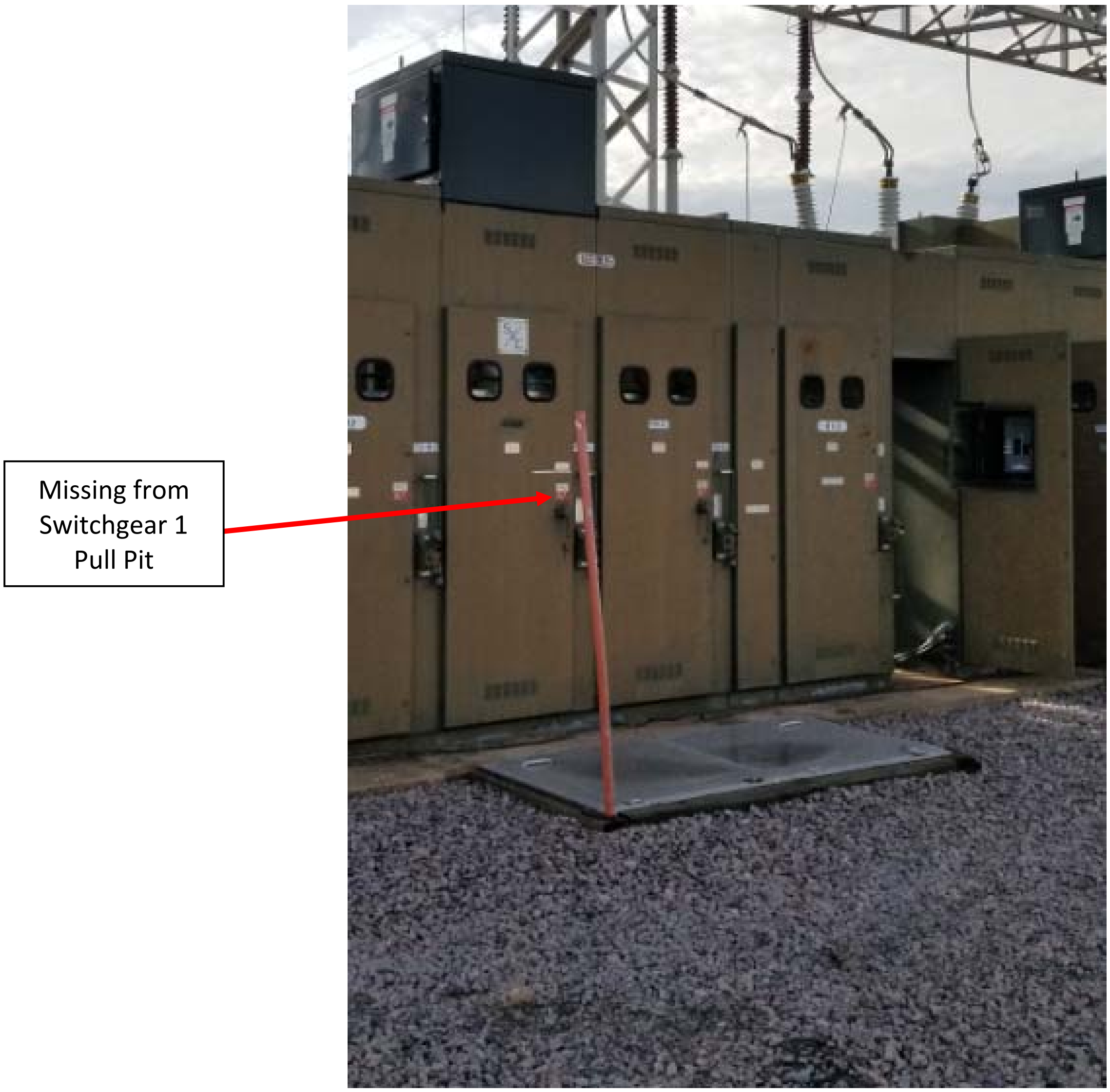

Figure 4-8 – Switchgear 2 Pull Pit

Figure 4-8 depicts a marker rod on the pull pit of Switchgear 2 that is currently missing from the pull pit of Switchgear 1. The pull pit construction will not withstand the weight of a vehicle. The marker should be replaced to prevent a vehicle from accidentally driving across the pull pit.

Figure 4-9A – Switchgear 1 Ground wire

Figure 4-9A depicts the ground wire running across Switchgear 1 and Switchgear 2. It appears this ground conductor may have been buried in front of the switchgear foundation originally and was moved due to the pull pit access. There are various areas where the wire sticks out and could be a potential tripping hazard. The aluminum frame and both pull pit covers should be bonded to ground on the Switchgear 1 and 2 pull pits. Currently, only one side of the pull pit cover is grounded.

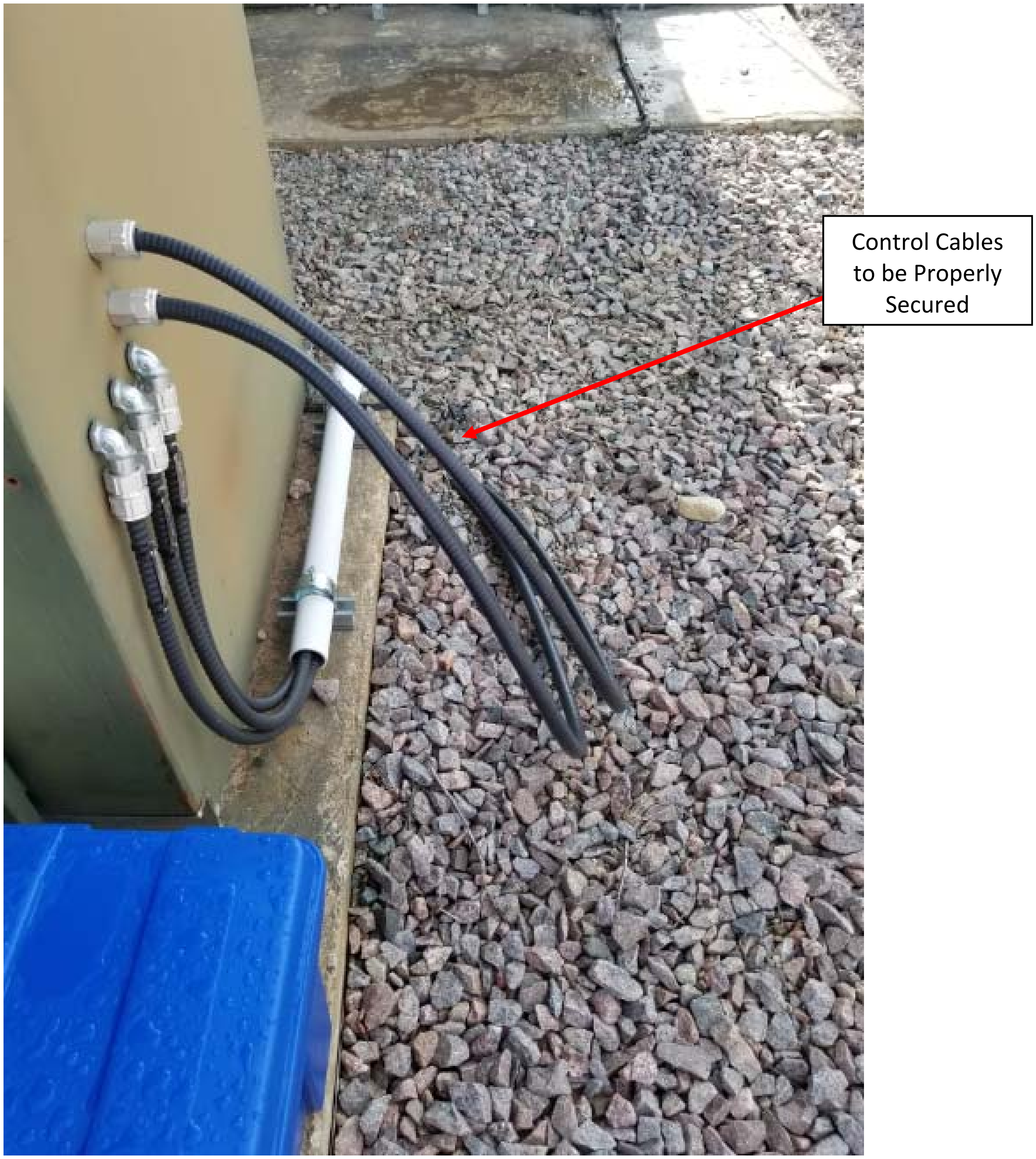

Figure 4-9B – Switchgear 1 Control Cables

Figure 4-9B depicts Switchgear 1’s control cables. These cables should be secured.

4.2 Switchgear 2 (B2-BUS)

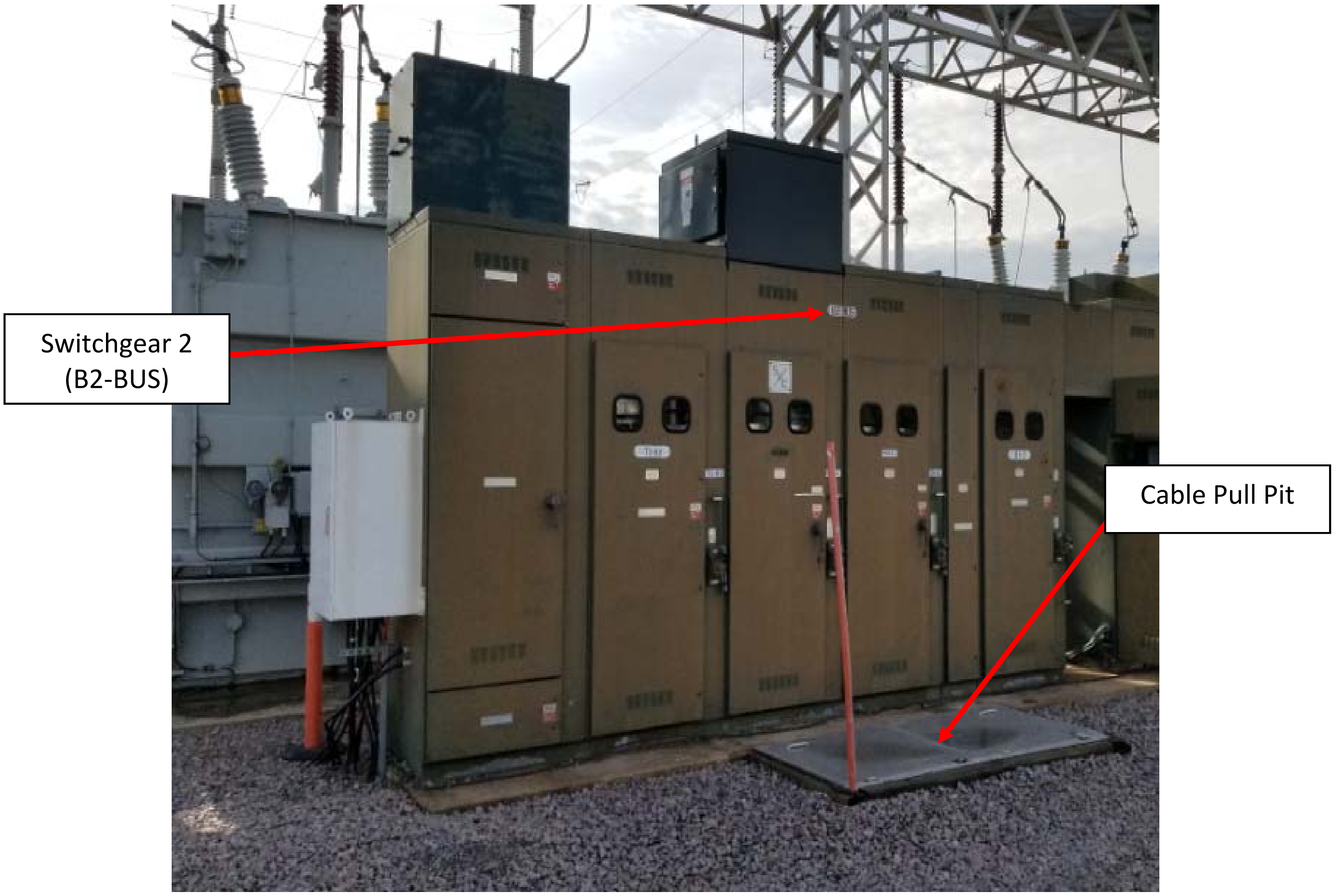

Figure 4-10 – Switchgear 2 (B2-BUS)

Figure 4-10 depicts Switchgear 2 (B2-BUS) and cable pull pit. The cable pull pit and entrance into the Switchgear was filled with water. Figure 4-11A depicts the water inside the pull pit and Figure 4-11B depicts the water of the pull pit inside the Switchgear (there was water present in both Feeder A-L and Feeder D-L). Figure 4-11C depicts a broken hinge on the aluminum door of the pull pit. It should be noted that the discoloration of the water in Figure 4-11A (presumably oil) is coming from the leakage of the out of service transformer T3 and possibly from previous oil leakage within the substation yard. Water appears to be entering by various points including around the switchgear cells through the gaskets, from the unsealed conduits to the feeder poles and around the base of the switchgear. The persistent moisture within the switchgear has caused significant corrosion on the exposed bus, degraded some of the internal cell wiring and creates a high moisture environment within the gear.

Figure 4-11A – Cable Pull Pit

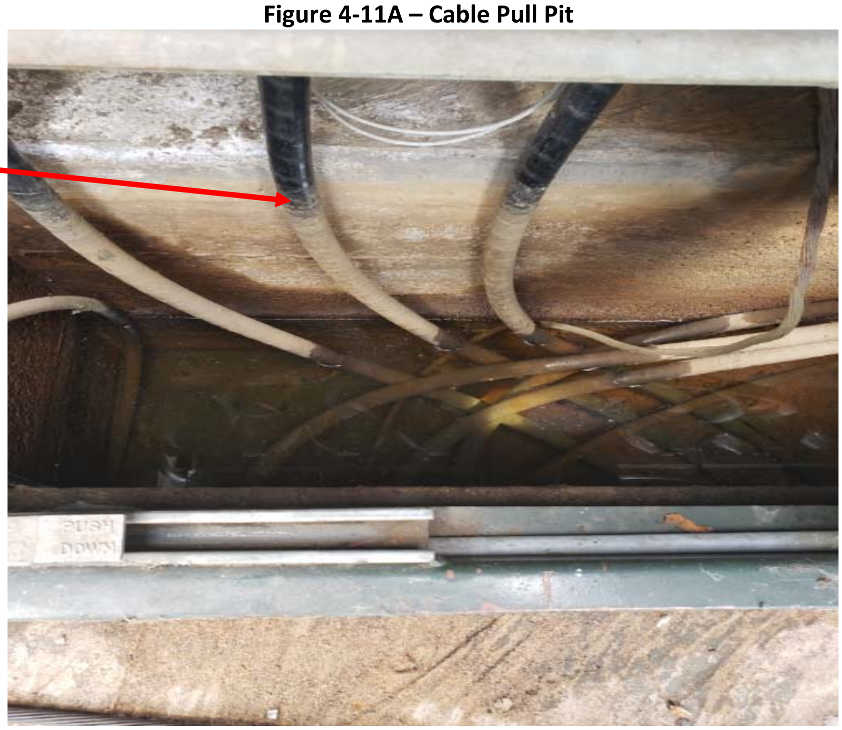

Figure 4-11B – Cable Pull Pit Inside Switchgear

Broken Hinge

Figure 4-11C – Cable Pull Pit Door

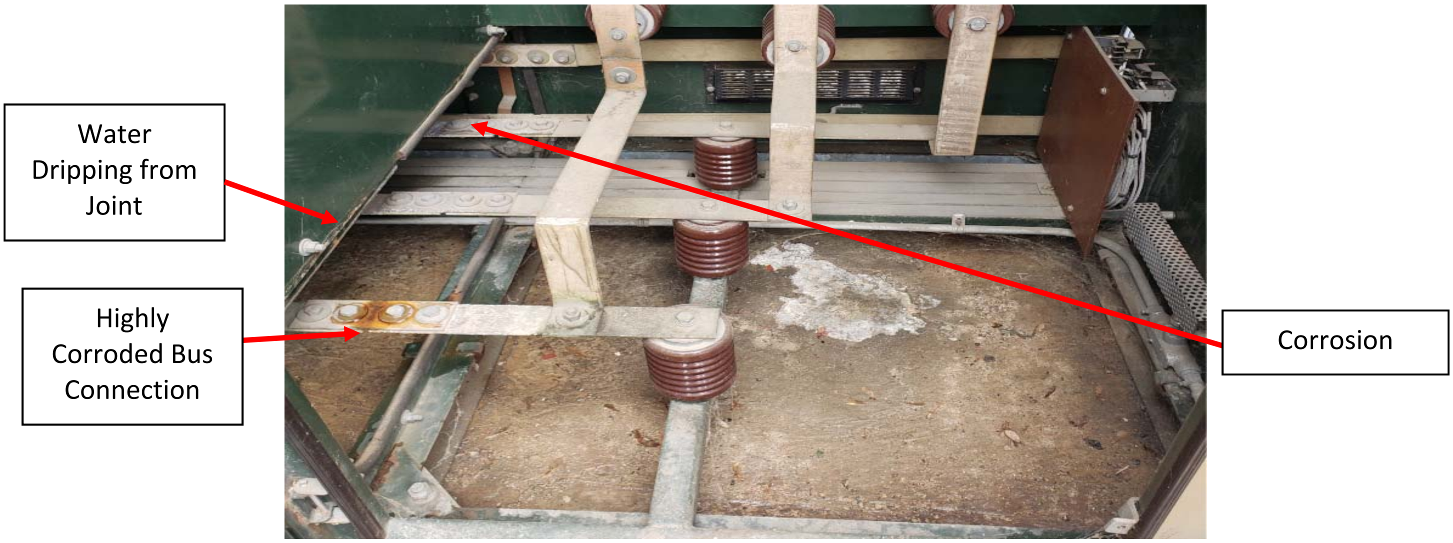

Figure 4-12 – T2-B2

Figure 4-12 depicts the rust, corrosion and water inside the T2-B2 cell of Switchgear 2. There are multiple areas affected. As with Switchgear 1, the top of Switchgear 2 should be resealed to prevent future leaking of water into the cells.

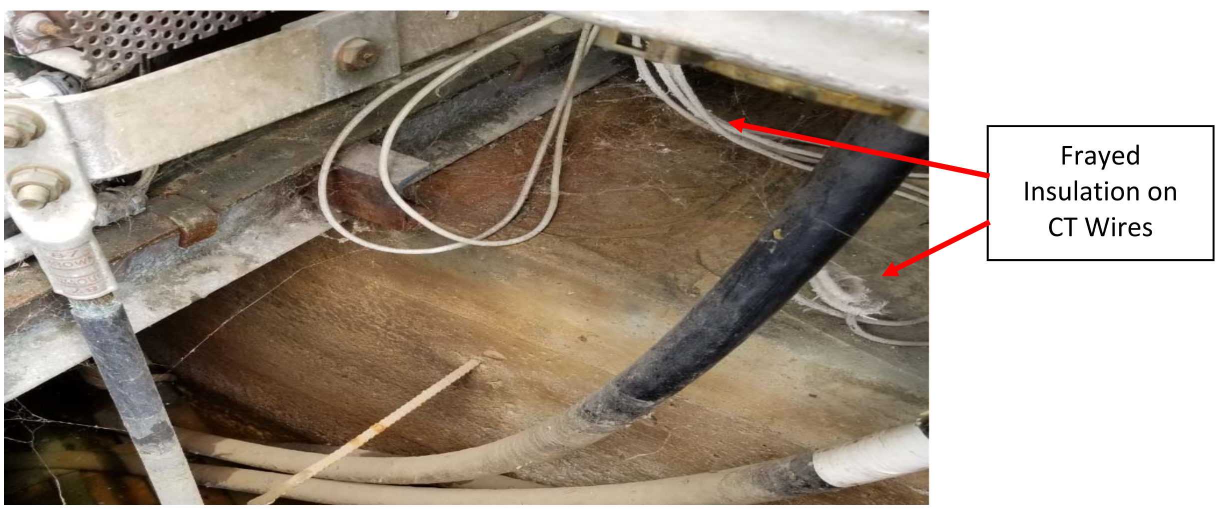

Figure 4-13 – Feeder A-L

Figure 4-13A depicts the frayed insulation on metering CT wires inside feeder A-L. The insulation is disintegrating and any flexing or touching on the insulation will cause it to crumble and expose bare copper.

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Burn Marks From Explosion

Figure 4-14A – B1-2 Door (Old Tie Switch)

Figure 4-14B – B1-2 (Old Tie Switch)

Figure 4-14A depicts burn marks from an explosion caused by a lightning strike (as explained by Kenora Hydro) on the door to the B1-2 cell. Figure 4-14B depicts the inside of the B1-2 cell which was previously a tie switch that connected Switchgear 1 and Switchgear 2. Due to multiple lightning strikes which caused considerable damage to the cell, the tie switch had been removed and it is currently a spare cell. The bus connection between Switchgear 1 and Switchgear 2 has also been removed. Only the ground bus bar remains.

4.3 TX – 1

Figure 4-15 – T1

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Figure 4-16 – T1 Connection

Figure 4-16 depicts one of the connections on Transformer T1 to the Calisto where minor oil weeping is present. This was the only area with any visible oil leakage from Transformer T1.

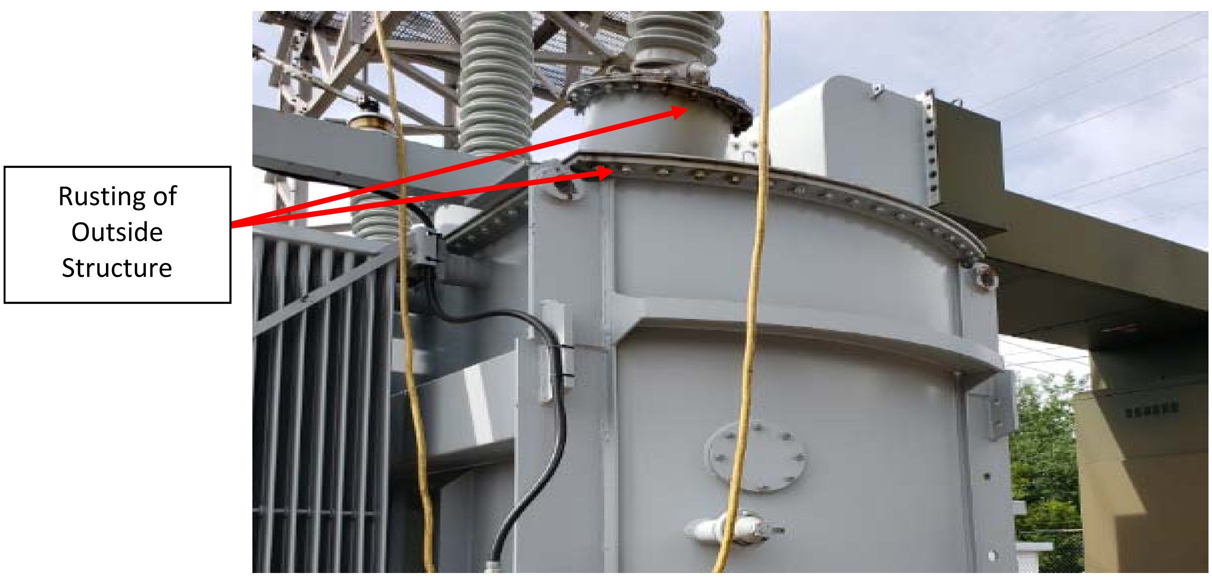

Figure 4-17– T1

Figure 4-17 depicts minor rusting along the outside structure of Transformer T1.

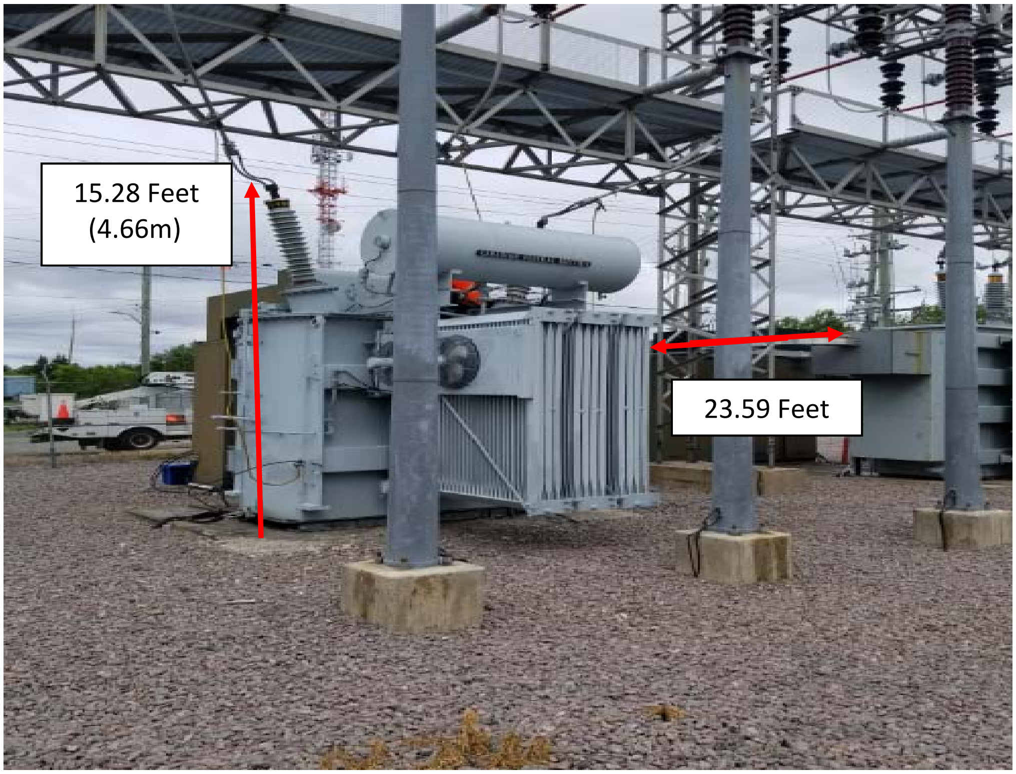

Figure 4-18A – T1 and T2

Figure 4-18B – Switchgear 1 and T1

Figure 4-18A and 4-18B depict clearances from Transformer T1 to Transformer T2 and Switchgear 1 to Transformer T1 respectively. T1 and T2 are located close together which could be an issue if one fails. The clearance from ground to the live part is approx. 4.66m (15.28 ft) for transformer T1. OESC requires a minimum of 4.6m (15 ft) for areas of heavy snow load and pedestrian access only.

Figure 4-19 – T1 and Foundation

Figure 4-19 depicts Transformer T1 and its foundation. The foundation is slab on grade with no oil containment. It should be noted that there was no visible oil leakage from Transformer T1. Transformer T1 contains approx. 2855 gallons of oil (10,800 L). Factory Mutual Standards require containment for any transformer with more than 500 gallons (1893 L) of mineral oil and is best practice. Any major oil leakage would cause oil to flow into the switchgear and into the nearby drainage ditch.

Cracked and Broken Foundation

Figure 4-20 – T1 Foundation

Figure 4-20 depicts Transformer T1's foundation. The corners of the foundation are chipped and cracked as shown. The spalling is most likely due to the age and moisture content. There are also various other areas with chips and cracks along the perimeter.

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Dehydration Breather

Figure 4-21 – T1 Dehydration Breather

Figure 4-21 depicts Transformer T1's dehydration breather. A Report from PSS on Oct 6, 2015 indicate that the gel was changed to orange and should be replaced when 90% of the beads are no longer orange.

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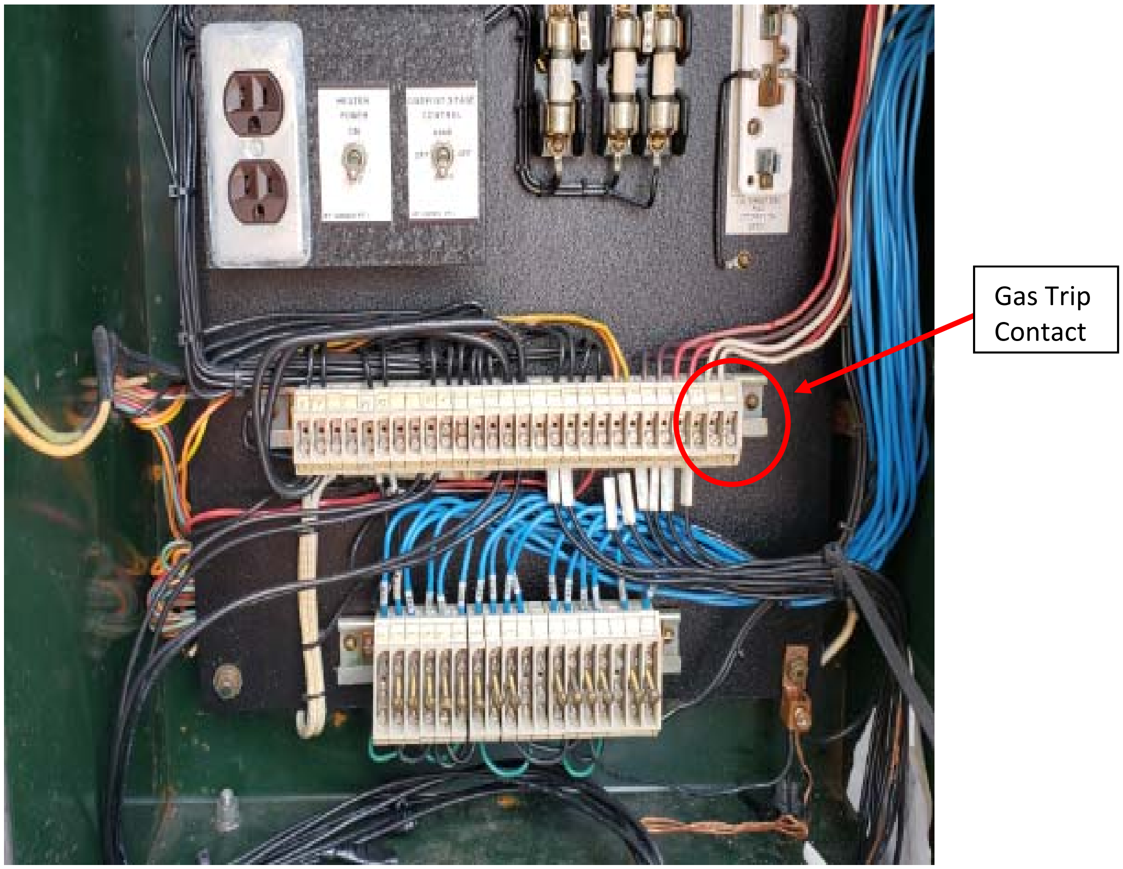

Figure 4-22 – T1 Trip Contacts

Figure 4-22 depicts Transformer T1's contacts. It appears that the gas trip contacts are not connected. Wiring should be field audited, and drawings created for reference and future trouble shooting in an emergency.

4.4 TX – 2

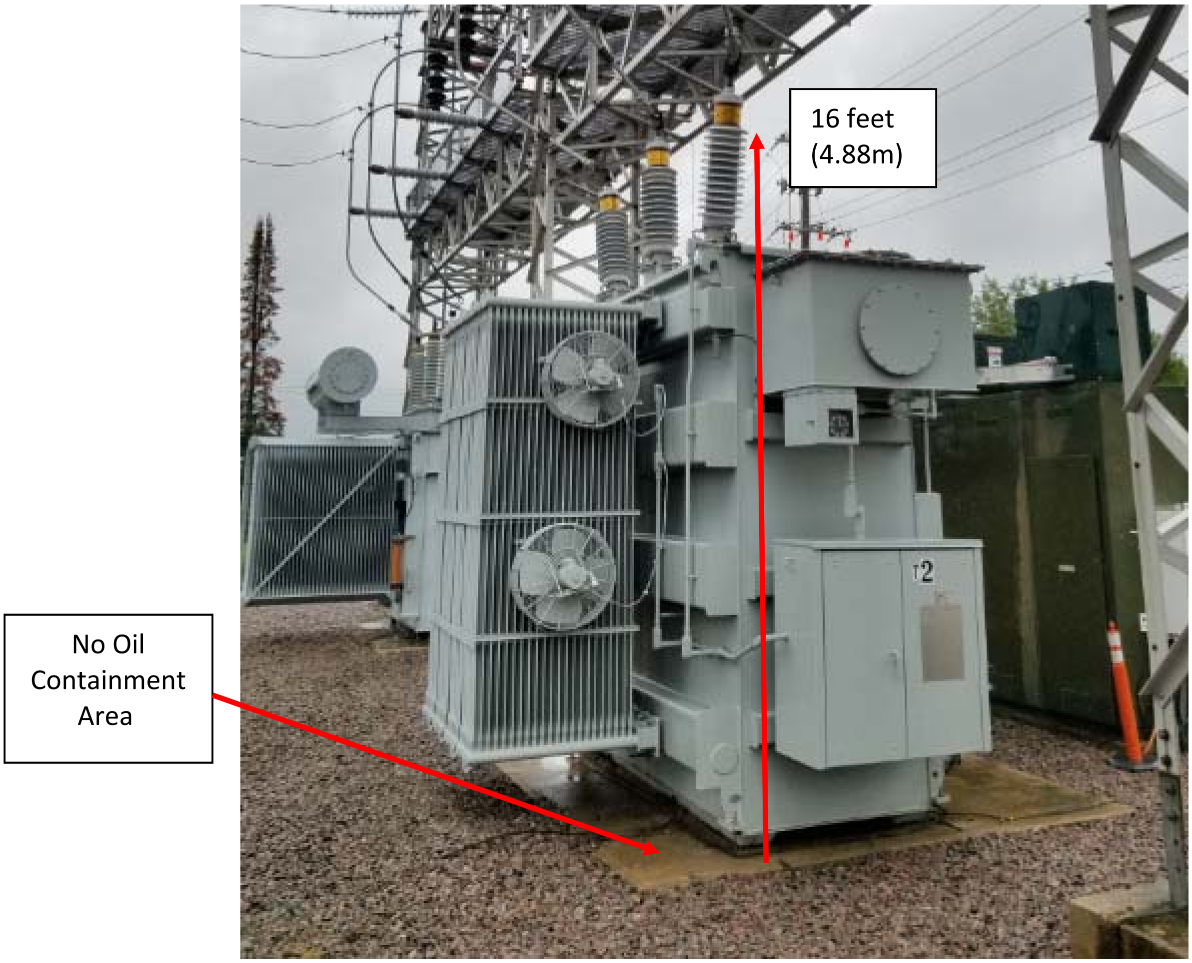

Figure 4-23 – T2

Figure 4-23 depicts Transformer T2 and its foundation. The clearance from ground to the live part is approx. 4.88m (16 ft) for transformer T2. OESC requires a minimum of 4.6m (15 ft) for areas of heavy snow load and pedestrian access only. The foundation is slab on grade with no oil containment. It should be noted that there was no visible oil leakage from Transformer T2. Transformer T2 contains approx. 3640 gallons of oil (13,779 L). Factory Mutual Standards require containment for any transformer with more than 500 gallons (1893 L) of mineral oil and is considered best practice. Any major oil leakage would cause oil to flow into the switchgear and into the nearby drainage ditch.

Rusting of Outside Structure

Figure 4-24 – T2 Structure

Figure 4-24 depicts minor rusting along the outside structure of Transformer T2.

Cracked and Broken Foundation

Figure 4-25 – T2 Foundation

Figure 4-25 depicts Transformer T2’s foundation. The corners of the foundation are chipped and cracked as shown. The spalling is most likely due to the age and moisture content. There are also various other areas with chips and cracks along the perimeter.

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Figure 4-26 – T2 and T4

Figure 4-26 depict the clearance from transformer T2 to transformer T4.

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4.5 TX – 3

Figure 4-27 – T3

Figure 4-27 depicts the out of service Transformer T3. There are various visible problems with this transformer, and it should be completely tested before being put into service. The option to have the transformer refurbished similar to T1, T2 and T4 could be completed to provide a spare, should one of the in-service transformers fail. The transformer has been leaking oil from the thermal well fittings and gas accumulation piping. The seepage is minor but appears to be continuous from previous reports. Transformer T3 has had some parts removed from the transformer. The winding and oil temperature gauges should be replaced, various parts within the control cabinet have been removed and previous testing has indicated that there are issues with some of the alarm and trip contacts. The porcelain insulators should be inspected for damage and cleaned before being energized. The gasket on the thermal well needs to be replaced. Missing part replacement will be required if this unit is to be a viable spare in the future.

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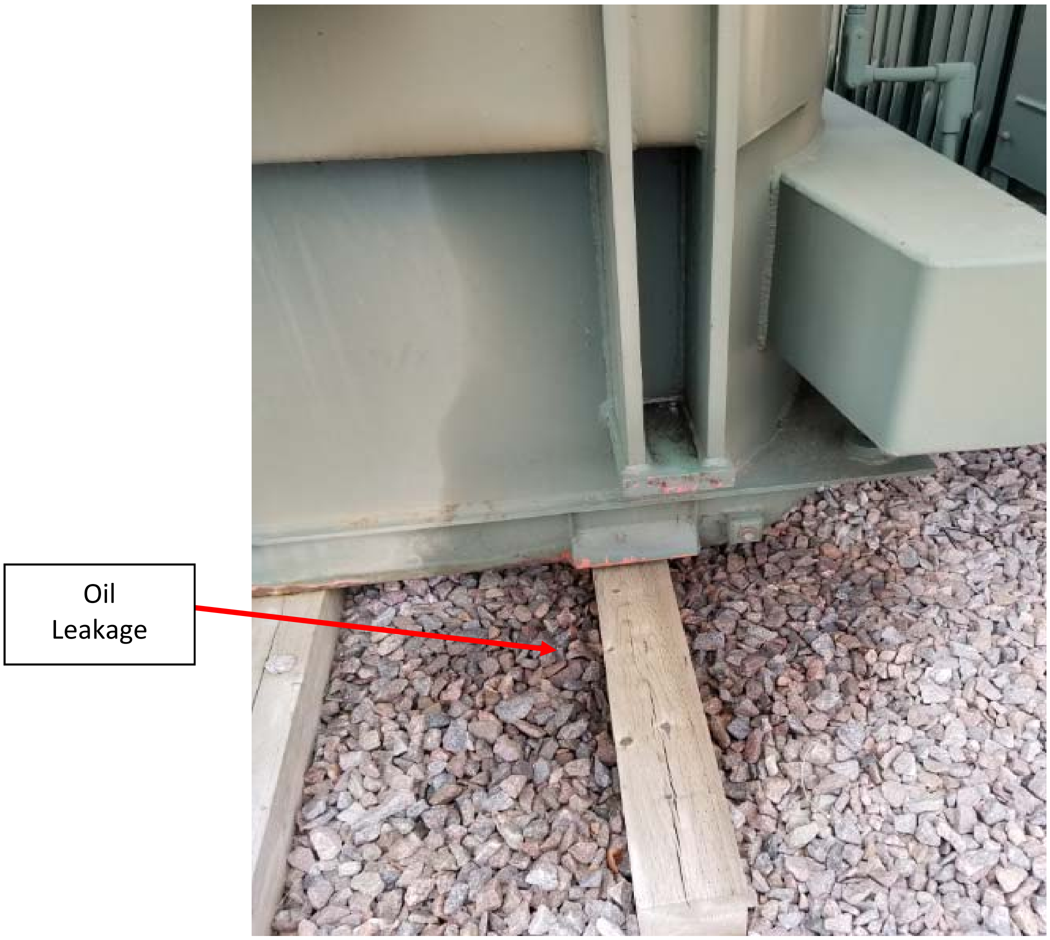

Figure 4-28 – T3 Oil Leakage

Figure 4-28 depicts the oil leaking from Transformer T3.

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4.6 Switchgear and TX – 4

Due to the switchgear and T4 remaining in service, no internal inspection was completed.

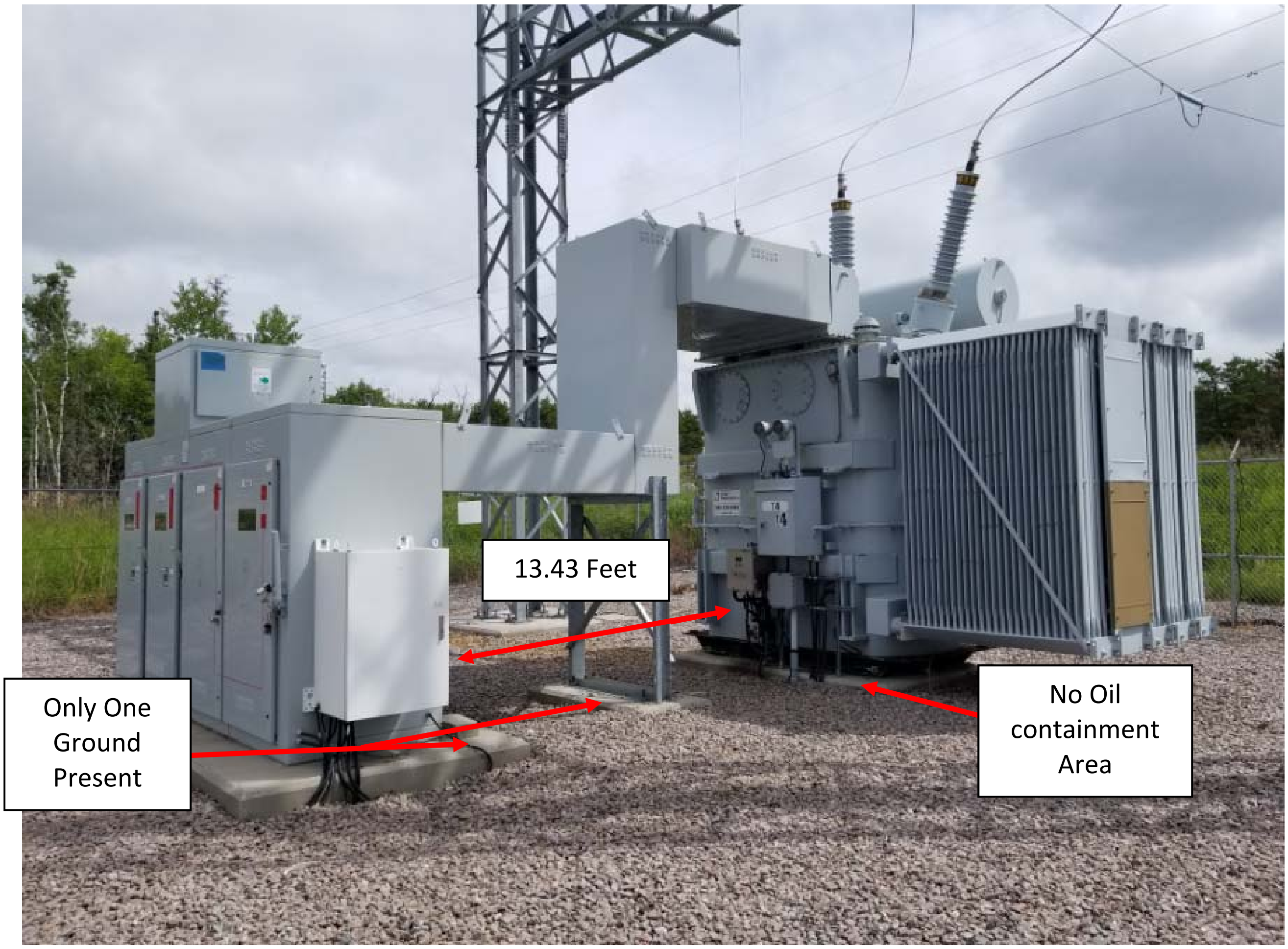

Figure 4-29 – Switchgear and T4

Figure 4-29 depicts Switchgear and Transformer T4. The clearance between the two is shown. There was only one ground present on the switchgear and bus duct support structure. The switchgear and bus duct support structure should be grounded on both sides for safety. Transformer T4 has no oil containment and contains 2190 gallons (9955 L) of mineral oil. Factory Mutual Standards require containment for any transformer with more than 500 gallons (1893 L) of mineral oil and is considered best practice. Any major oil leakage would cause oil to flow into the switchgear and into the nearby drainage ditch.

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Figure 4-30 – Base of Switchgear 4

Figure 4-30 depicts the base of the switchgear. There were multiple area's where the base had a damaged seal. These areas should be resealed.

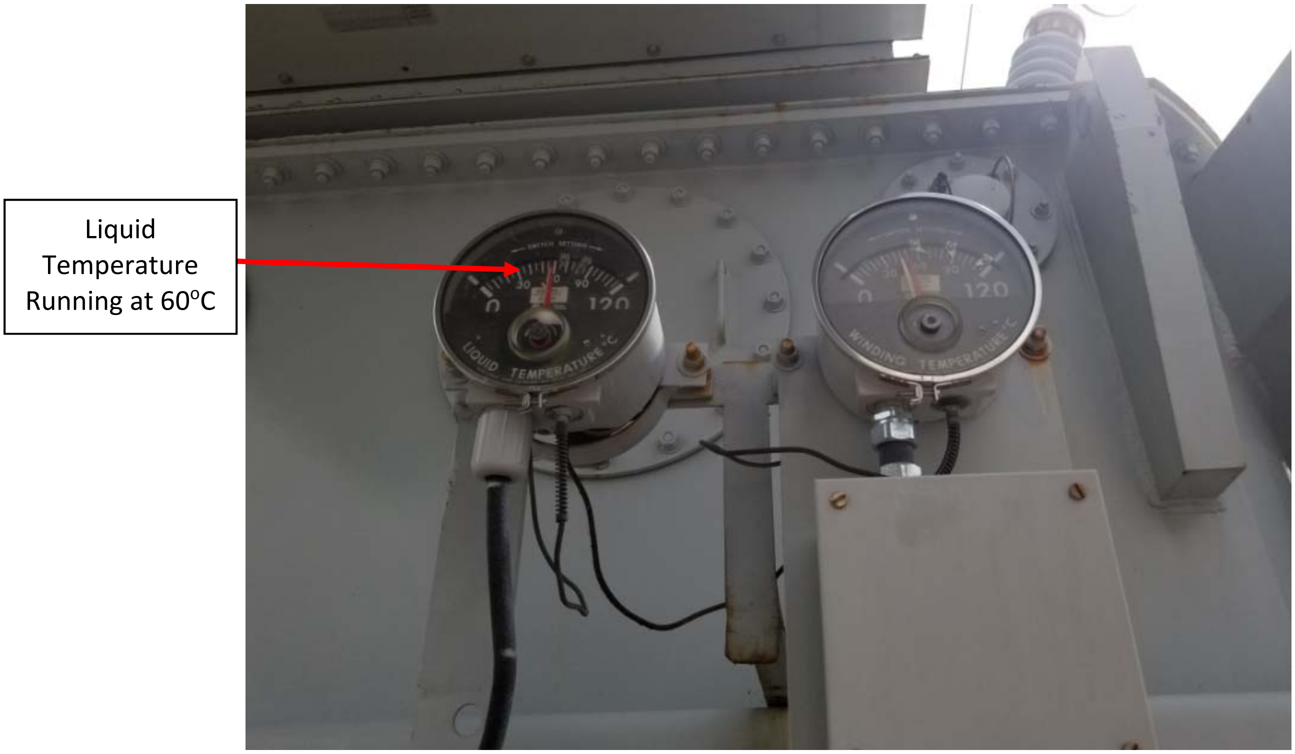

Figure 4-31 – T4 Heat Measurements

Figure 4-31 depicts temperature measurements of Transformer T4. The liquid temperature is at 60°C. The radiator valves may be closed which should be confirmed.

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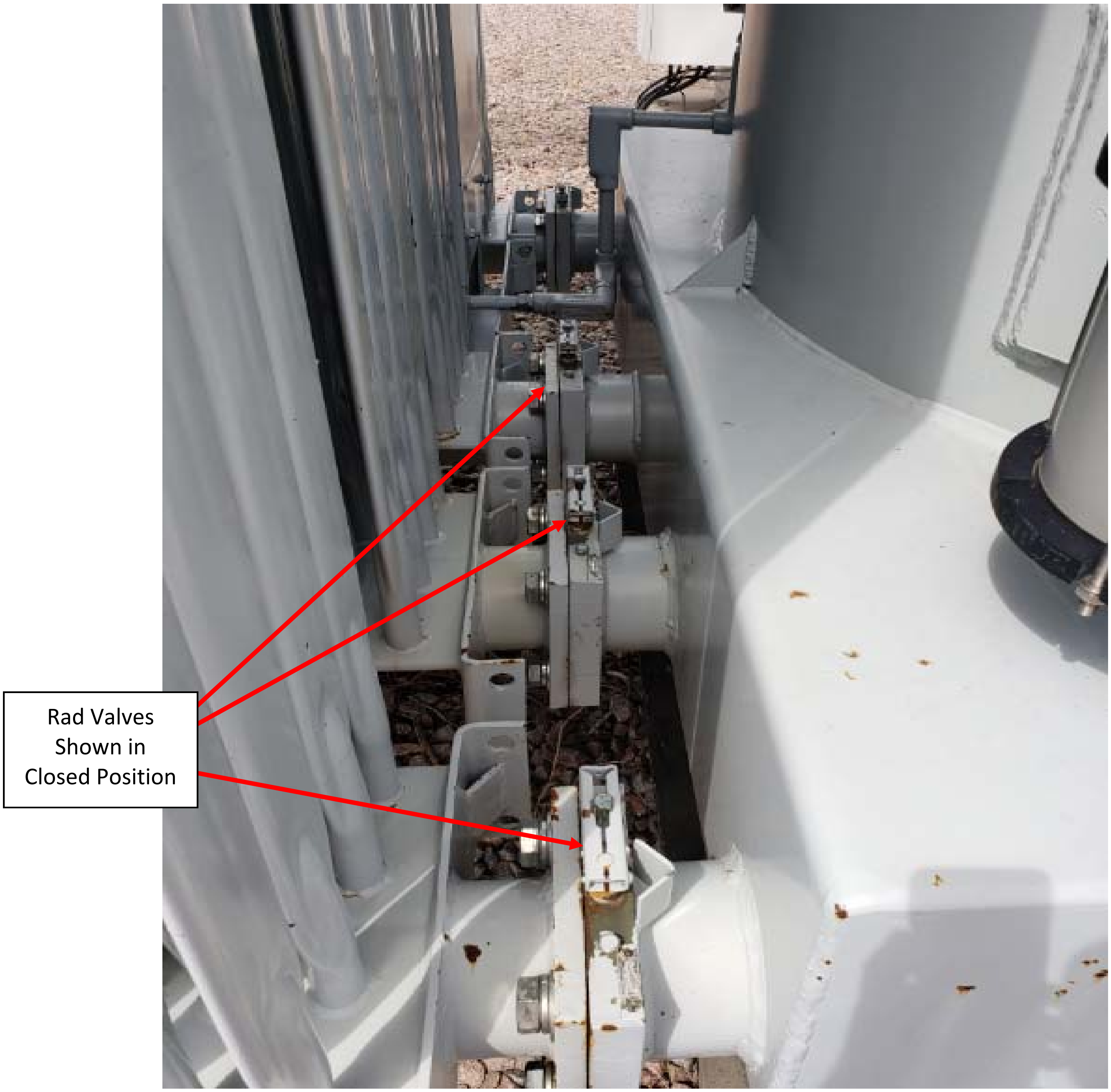

Figure 4-32 – T4 Rad Valves

Figure 4-32 depicts the radiator valves in the closed position. Kenora Hydro informed us that even though the radiator valves were shown in the closed position, they were in fact open. This detail should be confirmed, and the labels adjusted as required.

4.7 Recloser and Switch Poles Inside Substation Yard

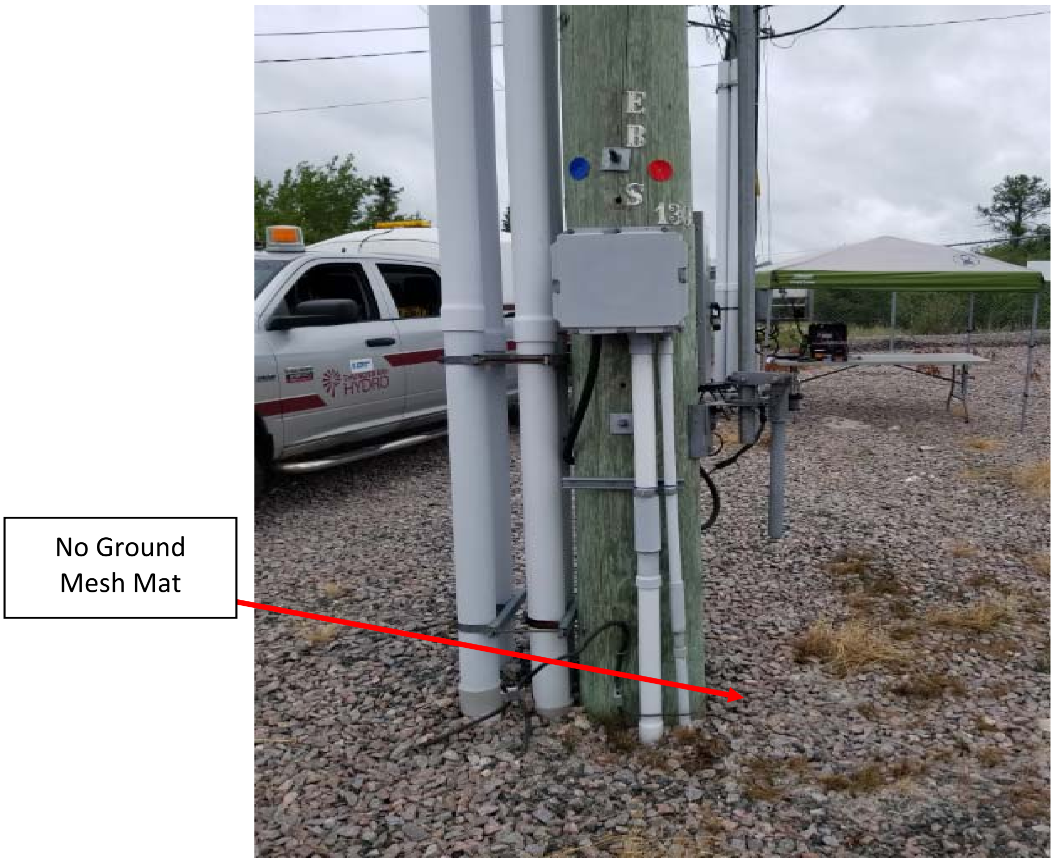

Figure 4-33 – Substation Pole

Figure 4-33 depicts a substation Pole. The area below the switch should have a ground mesh mat installed or the workers should be provided with proper portable switch mats that can be connected to the pole down ground and handle. This is to ensure that when a worker is operating the switch that he/she be at the same potential as the switch.

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Only One Ground on Handle Bracket

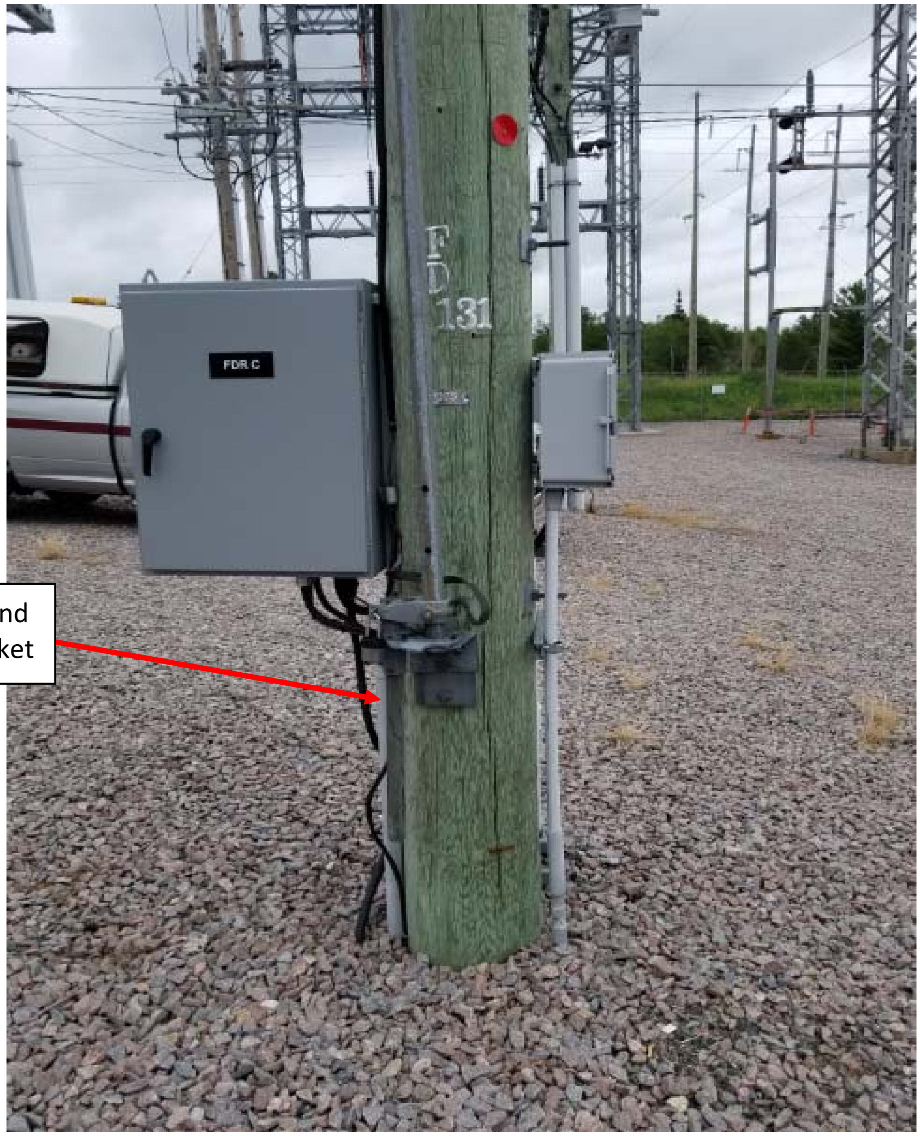

Figure 4-34– Substation Pole 131

Figure 4-34 depicts pole 131. The switch handle on this pole has only one ground connection. Refer to Appendix A for typical switch grounding. It should be noted that all non-energized metal brackets on all poles be grounded as well.

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4.8 Perimeter Fence

Broken Crossmember

Figure 4-35– East Corner Top Fence Crossmember

Figure 4-35 depicts the East corner of the perimeter fence. A broken crossmember is shown. All broken crossmembers should be repaired.

Broken Tension Wire

Figure 4-36– East Side Fence Bottom

Visible Ground Wire

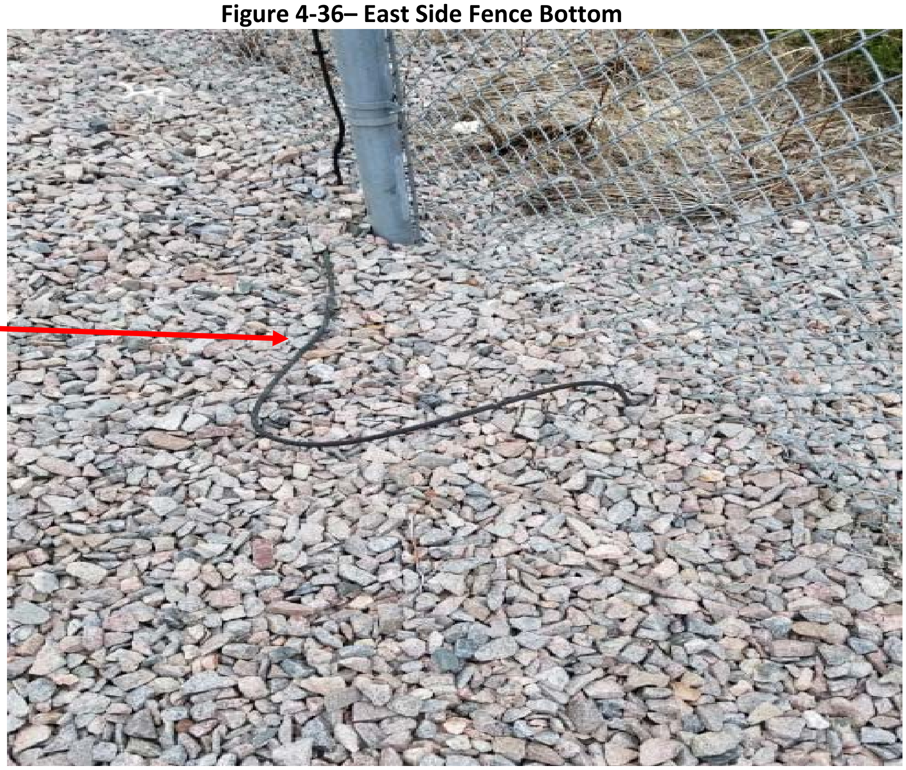

Figure 4-37– North Side Fence Bottom

Figure 4-38– East Side Fence Cadweld Connection

Figure 4-36 depicts a broken tension wire on the bottom of the east side of the perimeter fence. Broken tension wires should be fixed to ensure no unwanted entry. Figure 4-37 depicts a visible ground wire on the North side fence. There are various areas along the perimeter where the ground wire is showing. These ground wires should all be buried under the rock. Figure 4-38 depicts a corroded Cadweld connection near the east side of the perimeter fence. This should be replaced.

Gap Between Upper and Lower Fence

Figure 4-39– East Side Fence Tie

Large Gap

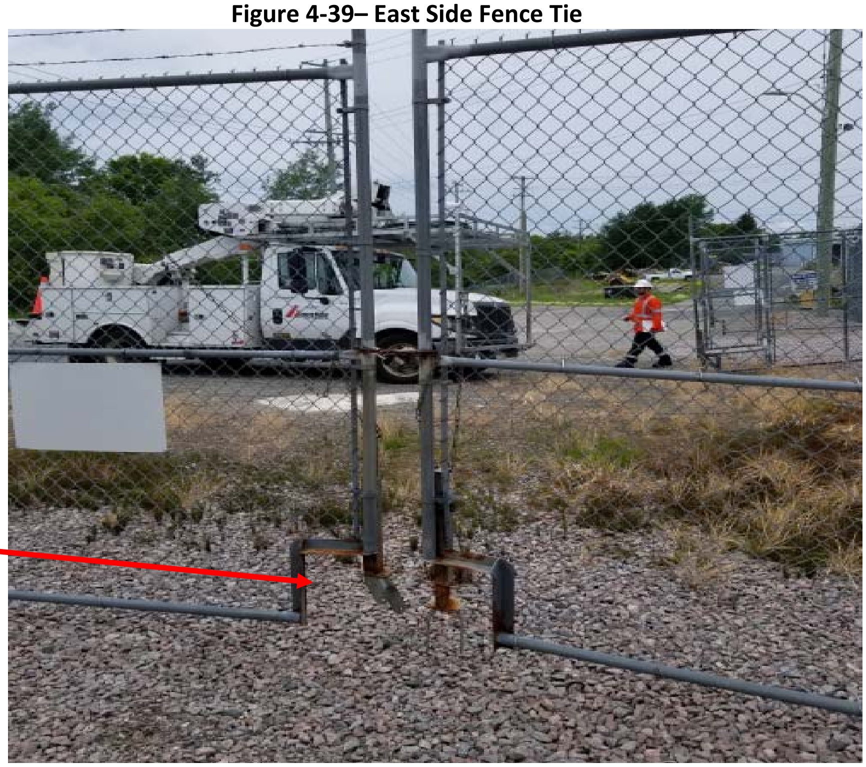

Figure 4-40– South Side Fence Front

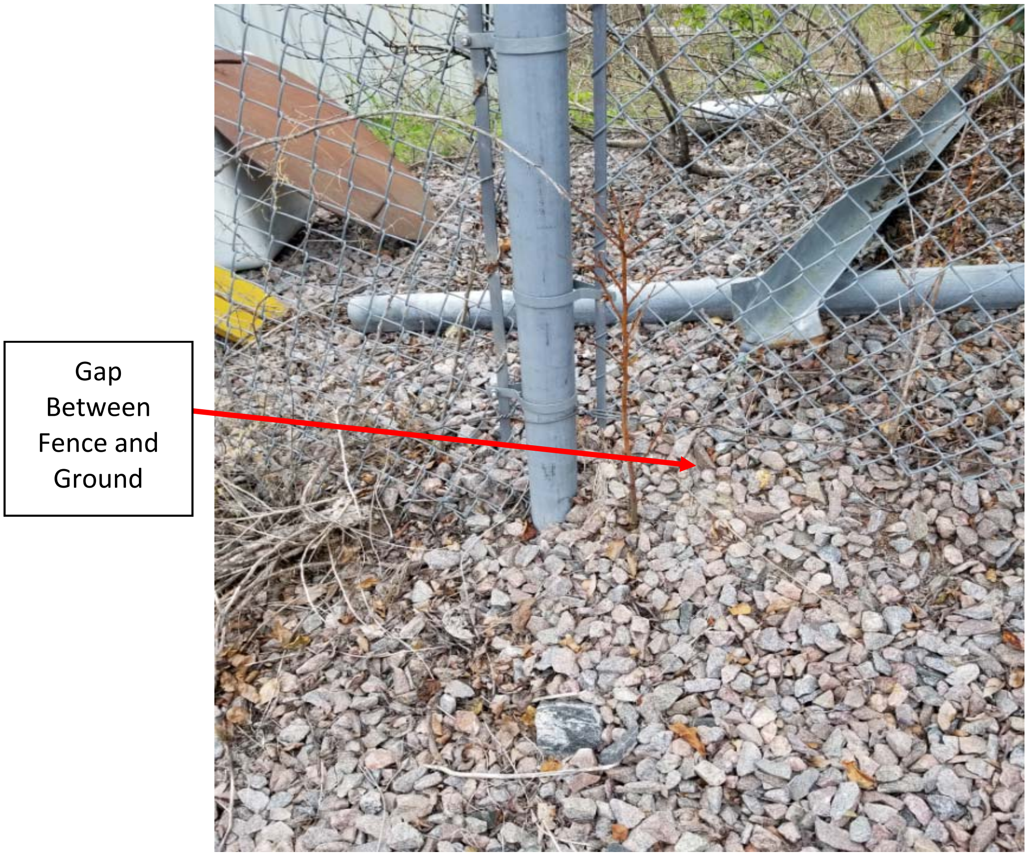

Figure 4-41– South Side Fence Gap

Figure 4-39 depicts an area where there is a gap between the upper and lower fence. Figure 4-40 depicts an area where there is a gap between the south front fence. Figure 4-41 depicts a gap between the ground and tension wire of an area of the south side fence. All of these areas should be tied together or blockaded to ensure no unwanted entry.

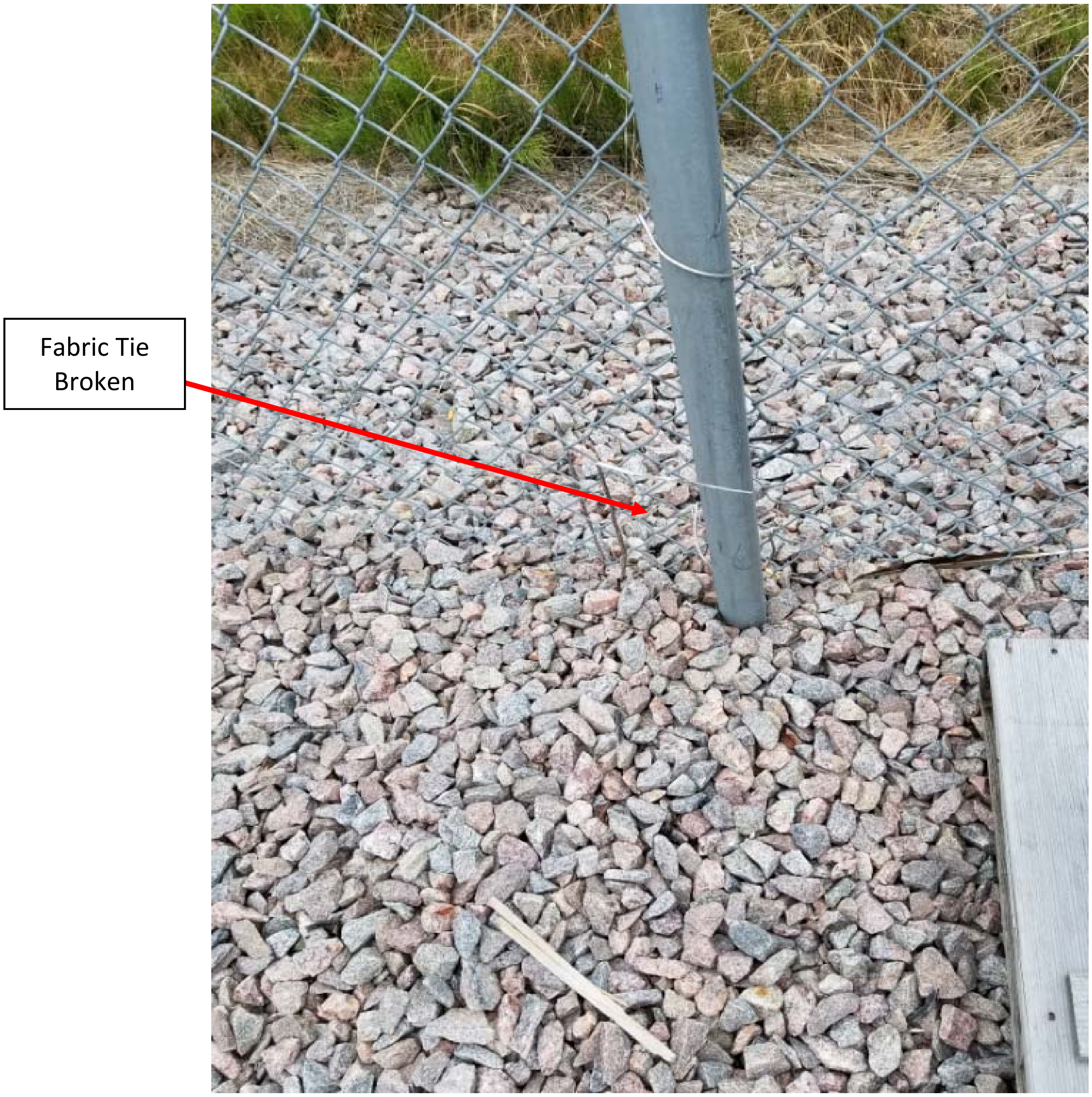

Figure 4-42– North Side Fence Post

Figure 4-42 depicts a broken fabric tie at the bottom of a north side fence post. There are many broken fabric ties on the fence that should be repaired to prevent any unwanted entry into the substation yard.

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Figure 4-43– North Side Fence Barbed Wire

Figure 4-43 depicts barbed wire on the north side fence that is ungrounded. All barbed wire should be grounded (where the barbed wire deadends).

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No Isolation or Grounds on Side Fence

Figure 4-44– Perimeter and Side Fence

Figure 4-44 depicts a side segment fence which is part of the perimeter fence. This segment of fence is not grounded or isolated from the substation fence. If the perimeter fence remains connected to the substation fence, it should be grounded as per the OESC.

Figure 4-45– Main Gate

Figure 4-45 depicts the man gate. There is no grounding present connecting the man gate to ground. This should be connected as per the OESC.

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4.9 Miscellaneous

Marette's On Security Camera Wiring

Figure 4-46– Security Camera's

Figure 4-46 depicts the security camera's inside the substation. There are what appear to be Marette's on the security camera wiring. These should be replaced with a proper weather proof seal.

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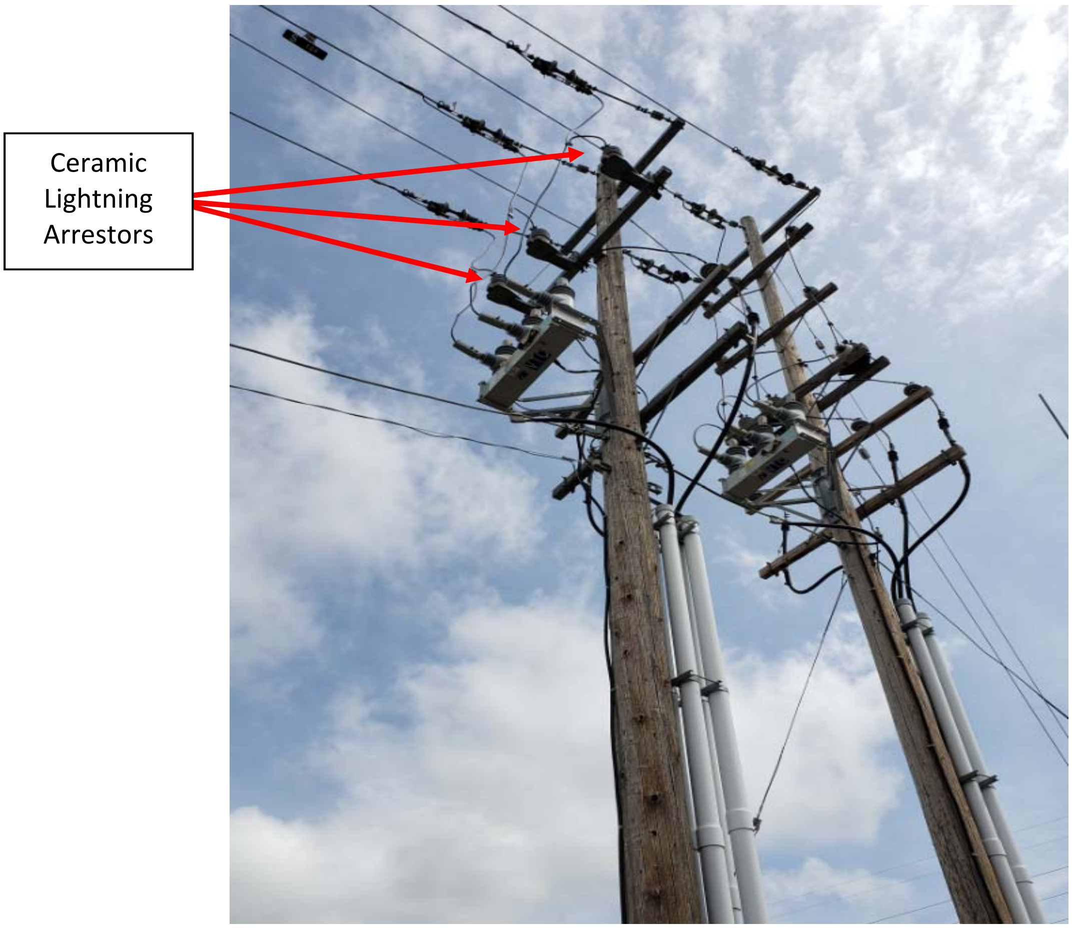

Figure 4-47– Substation Pole Lightning Arrestors

Figure 4-47 depict lightning arrestors on the feeder poles. These arrestors are currently ceramic. They are prone to chipping and cracking. It is important to keep them clean.

Figure 4-48– Kirk Key configuration at Switchgear 2

Figure 4-48 depicts the kirk key configuration at Switchgear 2 main Transformer 2 disconnect. There are no kirk keys at the primary side disconnects of Transformers T1 and T2. This means that Switchgear 1 and Switchgear 2 can be operated while the primary switch is still closed. Although the switches in the switchgears are load break switches, it is recommended to have the primary switch open before operating these switches. This will ensure the switchgear is de-energized when an operator closes or opens the switch, providing a greater level of safety given the age, condition and damp environment of the switch. A kirk key scheme should be implemented in addition to Synergy North's switching procedure.

Figure 4-49– Overhead T1 and T2 Structure

Figure 4-49 depicts the overhead T1 and T2 structure. This structure has porcelain insulators on the switches and the stand off insulators. This type of insulator is prone to cracking and chipping. These should be inspected and cleaned regularly to avoid failure. Replacement insulator bells by the old T3 foundation should be inspected before using as a replacement as well. The brown insulator bells appear to be previously removed from service and are cracked/chipped.

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Figure 4-50– Old T3 Structure

Figure 4-50 depicts the old T3 structure. This area is sectioned off due to falling debris coming from the top of the structure.

5 Summary of Recommendations

Switchgear

The remaining useful life of the switchgear is estimated at 8-10 years, meaning Switchgear 1 and 2 should be replaced by that time.

Switchgear 1 and 2 both had water ingress into their respective pull pits and Switchgear cells. This should be dealt with immediately by sealing all joints of the switchgear along with conduits entering the pull pits. A foam or Sikaflex type sealant would be best. The Switchgear cells should also be gasketed on top of each cubicle and all the way around. The water in the pull pits and water leaking into the switchgear is creating severe humidity within the gear which will eventually lead to failure. Covers (non-ferrous or non-conductive material) over the pull pits within the switchgear cells would also help limit the amount of moisture and condensation within the switchgear due to evaporation. The use of an industrial sump pump would also be beneficial to drain the water when it becomes excessive. A permanent solution would be to direct bore a drainpipe from the slope adjacent to the roadway into the bottom of the pull pits.

Switchgear 1 and 2 had corrosion present at most joints on the bus bar. This should be dealt with immediately, by having these areas disconnected, wire wheeled and the re-torqued to remove the rust and corrosion. Failure to clean the bus could lead to a potential arc flash incident or excessive bus heating causing a failure.

There was no fusing present in each feeder section of both Switchgear. This should be dealt with immediately by putting fusing in place of the solid blades. This will improve protection and coordination of the Switchgear.

The tie switch cell in Switchgear 2 was removed due to multiple lightning strikes. The switchgear cell had burn marks on the inside of the door. This and other areas of the Switchgear where rust is present should be cleaned and repainted immediately to help identify future arcing, corrosion leaking and other issues. It is also advisable to insert a new tie switch in the long term, to be able to implement a load sharing option in an emergency situation.

The insulation on the CT wires in feeder A-L of Switchgear 2 are extremely frayed and disintegrating. This should be dealt with immediately by replacing all CT wires inside feeder A-L. If these are left unattended the bar copper CT wires could short or cause an open CT condition which would result in catastrophic failure of the CT(s).

There is a long ground wire present along the front of both Switchgear 1 and 2 lineups. It is recommended that this ground conductor be properly secured or removed to eliminate any potential tripping hazard. This is not a major hazard, as it does not affect the functioning of the Switchgear, thus it is recommended to be completed in the short term.

The Switchgear pull pit marker rod on Switchgear 1 should be replaced. Both pull pit covers and frames should be grounded to the station electrode. This is not a major hazard, as it does not affect the functioning of the Switchgear, thus it is recommended to be completed in the short term.

Several cracked windows on the switchgear cell doors should be replaced/repaired as needed, to ensure the Switchgear is sealed properly to prevent any unwanted moisture. This is not a major hazard, as it does not affect the functioning of the Switchgear, thus it is recommended to be completed in the short term.

Control cables on the south end of the switchgear should be secured to avoid damage. This is primarily a precaution, as the chances of the cables being damaged are low and hence should be dealt with in the long run.

Switchgear T1 and T2 share a common ground bus through the switchgear. The ground bus is only grounded at one end in Switchgear T1. A second ground should be added from the station ground electrode to the Switchgear T2 ground bus for safety. This is a safety hazard, as it does not affect the functioning of the Switchgear, thus it is recommended to be completed in the short term.

The seal at the base of the Switchgear 4 is disintegrating and should be resealed. This is primarily a precaution, as the chances of it causing any problems are low and hence should be dealt with in the long run.

To ensure the Switchgear remains safe and in good condition it is recommended that it be inspected yearly, along with all other components within the substation. During this inspecting the Switchgear should be de-energized and cleaned thoroughly.

Transformers

Transformers T1, T2 and T4 have no oil containment areas. If any these transformers were to leak, it could cause extreme damage to the substation. This should be dealt with immediately by installing containment areas. A fully installed containment pit under the transformers would be the best but also the most expensive option. A curb around each transformer along with a Sorbweb type material (imbiber material) for a containment pad would be more cost effective. The oil mat would allow rain water to pass through but imbibe organic compounds (hydrocarbons) from penetrating.

The liquid temperature of Transformer T4 was running hot (60^{o} C). Three radiator valves on the east side were in the closed position but Nordmin was informed that they were in-fact open. It should be immediately confirmed which position these valves are in, and if in the closed position, it is advisable that they be opened to allow for greater circulation of oil, which will lower the liquid temperature of the transformer. If the liquid temperature of the transformer gets to hot, it could extreme damage

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to the transformer. Overheating will negatively impact the life of the transformer.

Transformer T3 has had some parts removed from the transformer. The winding and oil temperature gauges should be replaced, various parts within the control cabinet have been removed and previous testing has indicated that there are issues with some of the alarm and trip contacts. The porcelain insulators should be inspected for damage. Missing parts should be acquired and installed on the transformer if this unit is to be a viable spare in the future.

Transformer T1 had minor oil seepage coming out of a valve/hose fitting. This should be monitored to ensure the weeping remains minor. If the weeping increases, then it should be dealt with immediately by sealing the valve/hose fitting.

The foundation of Transformer T1 and T2 was cracked and chipped in various areas due to spalling. This should be considered for repair in the long-term if the foundation continues to degrade. Regular maintenance including patching and repairing the concrete to reduce degradation of the concrete foundation.

The distances between all the transformers were less than 50 feet with T1 and T2 being the closest together. Typical industry standards set by Factory Mutual requires a minimum distance of 50 feet between transformers of this size (oil quantity) or a blast wall installed. This is for loss prevention and Synergy North should check with their respective insurance company on the minimum distance between transformers required. It should be noted that utilities tend to follow their own standards and do not necessarily prescribe to the standards set forth by FM Global.

The Transformers should be inspected and tested yearly to ensure there is no damage to the bushings, leaking oil, temperature issues etc. that could cause premature failure.

Recloser and Switch Poles

The only issue observed with the Poles in the yard was proper grounding. All poles should have a ground mesh mat installed under every switch or a proper portable ground mat supplied to workers for operating the switches. Every switch and non-energized metal bracket should be grounded. This should be done in the long term as it does not cause an extreme hazard but it is imperative for worker safety. The typical switch grounding is shown in Appendix A.

Perimeter Fence

There were various areas on the perimeter fence that were not tied together or had large openings present. These areas should be properly tied together and blocked off to ensure no unwanted entry into the substation yard. A main point of concern was the front south side fence that had a very large opening present. This should be barricaded and blocked off. This should be dealt with immediately to prevent any damage or injuries from on outside source.

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The broken crossmembers, tension wires and fabric ties should all be fixed and replaced immediately to ensure the fence is safe and secure and prevents all unwanted entry.

The side fence that connects to the east side of the perimeter fence to the substation fence should be replaced by a wooden fence section. If not isolated from the substation fence, the perimeter fence should be properly grounded as per the OESC. This is imperative to protect the workers and public from possible shock hazards.

All ungrounded areas such as barbed wire and corner tie posts should be grounded. The visible ground wire that runs on the bottom of the fence should be properly buried and covered by rock. Grounding is key safety element in the substation and therefore, should be dealt with in the short term.

Grounding

A fall of potential test was completed at site to measure the impedance of the station ground grid. The fall of potential test was conducted by driving probes towards the operations building. The results of the test indicate an approx. Rg value of 3.14 Ohms. This value is below the recommended 4 Ohm value in the initial report but much higher than the required 0.80 Ohms listed in the final report and on the drawing. Additional grounding has been installed in the substation but there was no visible evidence that the ground wells with bentonite clay were installed. Further investigation is warranted (some digging will be required) and another test is recommended once permission from landowners around the site to access their land is granted. A recommended distance for the current probes is 488m (1600ft) to get a more accurate result. A brief summary sheet can be found in Appendix B

Miscellaneous

The Kirk Key system in the substation does not stop Switchgear 1 and 2 from being operated while the primary switch is closed. Although the switches in each Switchgear are load break switches, THEY SHOULD NOT BE OPERATED while the primary switch is closed due to the age and moisture within the gear. It is recommended that in the short term a Kirk Key be added to the primary side of the transformers to ensure that the primary switch be open before any work can be done within the Switchgear. A 3-cylinder transfer interlock block could be implemented to ensure that the feeders are isolated before the primary disconnect switches are operated. The Kirk Keys from the feeder disconnect switches would be used to release a key from the transfer block that would allow the primary disconnect to be opened. This would then release the existing key to open the switchgear main disconnects on Switchgear 1 and 2. A similar system should be installed on Switch 4 to achieve a similar switching procedure. It is recommended that this be completed in the long run, to ensure that the Switchgear switches are not operated unless the primary switch is closed.

Each feeder pole has ceramic lightning arrestors. These are prone to cracking and chipping, so it is important they be kept clean and regularly inspected. In the long term it is advisable to replace these with polymer lightning arrestors. Failure of the arrestors will prevent adequate protection during a

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lightning strike. Polymer insulators and arrestors have a longer lifespan and are less prone to catastrophic failure. Proper testing must be done regularly on the insulators/arrestors as per NETA and IEEE standards since a visual inspection is more difficult to detect issues.

Overhead T1 and T2, glass string insulators were present. These are prone to cracking and chipping. These string insulators are in close proximity to the Transformer T1 and T2 bushings and if chipping or cracking occurs, they could cause damage to the transformers and transformer bushings. This should be dealt with immediately by replacing the glass string insulators with polymer before failure occurs. Polymer insulators are lighter, stronger, less prone to vibration, more tolerant of pollution and do not fail catastrophically.

Overhead T1 and T2 has porcelain insulators on the switches and stand off insulators. These are prone to cracking and chipping and should be cleaned and inspected regularly. In the long term it is advisable to replace these insulators with polymer insulators before failure occurs.

The area behind Transformer T2 is sectioned off due to the falling debris of the old T3 structure. This should be dealt with immediately by removing the insulators, switches and equipment from the old T3 structure. It should be noted that full tension splices would need to be completed so that the insulators and structure could be removed due to the fact that the incoming line to T2 is spliced just before the structure and the substation insulators are still being used on the structure to support the line.

The security cameras inside the substation yard appear to have Marettes on the wiring. These should be replaced with a proper weather proof seal to ensure no water enters the wiring. This is not a major issue as it does not affect the functioning of the substation, hence should be completed in the long run

Structural Steel

The structural steel and respective foundations for T1, T2 and T4 appear to be in satisfactory condition. No major issues were visible during the inspection. The useful life of the structural steel is expected to be over 10 years.

All equipment testing should be done per NETA (International Electrical Testing Association) and IEEE standards as appropriate for the specific piece of equipment.

6 Signatures and Review

Report Prepared By:

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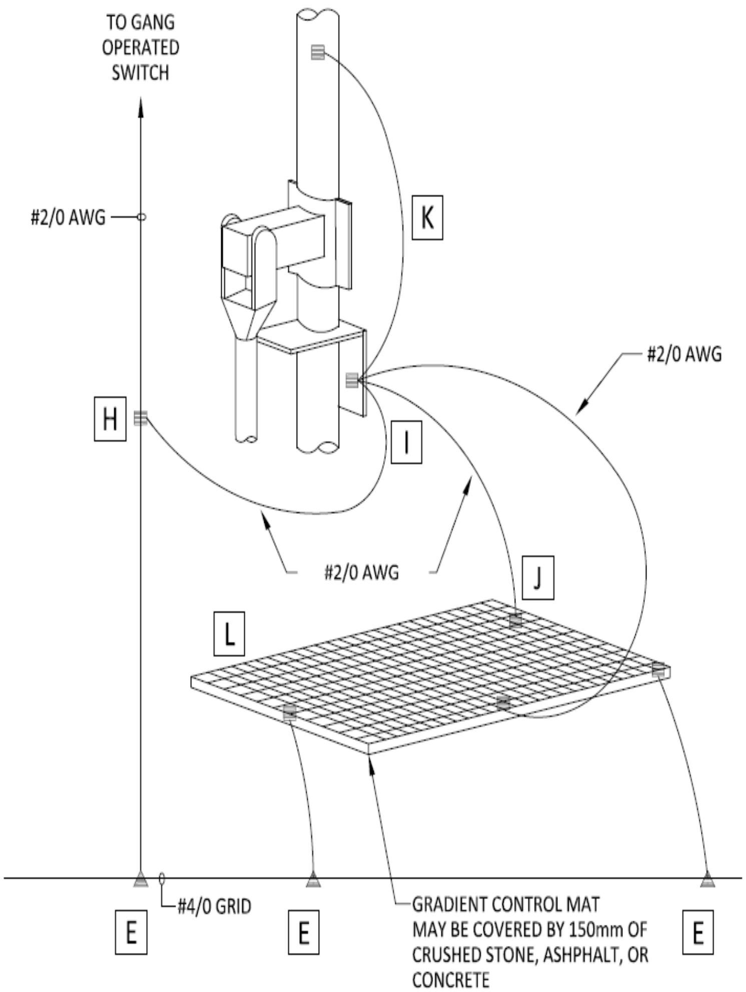
Nordmin Engineering, Ltd.

Report Reviewed By:

Jay Kruzliak, P.Eng
Senior Engineer – Power Systems
Nordmin Engineering, Ltd.

7 Appendix

A – Typical Switch Operator Grounding



LIST OF GROUND GRID CONNECTORS

ITEM	DESCRIPTION
E	#4/0 AWG TO #2/0 AWG CABLE TO CABLE CONNECTOR BURNDY CAT. No. YGHC29C26
H	#2/0 AWG TO #2/0 AWG BURNDY SERVIT CAT. No. KSA 2/0
I	2x #2/0 AWG TO STEEL, BURNDY SERVIT CAT. No. K2C28
J	#2/0 AWG TO WIRE CONNECTOR, BURNDY HYTAP CAT. No. KS29
K	FLEXIBLE COPPER BRAID, 12", BURNDY CAT. No. BE12
L	GROUND MAT, 6" x 6" MESH, 4' BY 6', T&B CAT. No. 64663

NOTES:

1. ALL GROUNDING STUDS ARE TO BE CONNECTED TO GROUND GRID WITH MINIMUM #2/0 AWG.

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B– Fall of Potential Grounding Study

Figure 4-51– Overhead View of Kenora Substation

System Data	
Body Weight (kg)	50
Fault Current (kA)	4.675
Division Factor (%)	Varies
Plot Step (m)	1
Fault Duration (s)	0.5

Soil Model	Touch Potential (V)	Step Potential (V)	GPR (V)	Rg (Ω)
Typical	882.9	184.0	14675	3.14