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EXHIBIT 2 - RATE BASE INTERROGATORIES

OEB STAFF

2-Staff-09

2023 Bridge Year Actual

Ref 1: Appendix 2-AA and Appendix 2-AB

Question(s):

a) Please update capital expenditures for 2023 bridge year in Appendix 2-AA format and Appendix 2-AB format (and update other related tabs in Chapter 2 Appendices accordingly). Please specify for which months actual data has been used and which months are forecast data.

SNC Response:

a) Please refer to the revised SNC_2024_Chapter2_Appendices_20231110 with the additional columns added to Appendix 2-AA to show both the year to date actuals for 2023 as well as Forecasted year-end expenditures for 2023, which include 9 months of actual data. See also the revised Appendix 2-AB for updated 2023 forecasted figures which include 9 months of actual data.

2-Staff-10

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.2.1.1.2 Mission, Vison, Values and Goals, page 7, .PDF page 105

Preamble:

Regarding its planning and investment's integrated approach, Synergy North states:

"These investments typically include the following:

- Customer driven connections.
- Regulatory requirements.
- System renewal and expansion.
- Renewable generation connections.
- General plant investments.
- Grid modernization assets.
- Regionally planned infrastructure."

Question(s):

a) Please explain how Synergy North ensures that condition-driven capital investments such as renewal projects are prioritized appropriately across and between the two pre-existing service areas and facilities?

b) Please explain how Synergy North has validated that the asset condition assessment and asset management systems of the two pre-existing service areas have been harmonized adequately to support appropriate prioritization.

SNC Response:

a) SNC employs a systematic approach to ensure that condition-driven capital investments, including renewal projects, are prioritized appropriately across its pre-existing service areas. This is performed by adhering to the asset management process described in Exhibit 2 Appendix 2-A, S.5.3 and further summarized below.

   - Comprehensive needs assessment: SNC reviews the needs of its customers, assets, and systems through engagement activities, condition assessments, studies and reports, and discussion with subject matter experts.
   - Planning investments: Candidate investments are created for both service areas considering elements from the outputs of the needs assessment. For example, this may include the quantity of assets requiring intervention based on their health, whether poor performing

assets warrant early intervention, whether growth creates opportunities for harmony between programs.

- Alignment with strategic objectives: The potential investments in each service area are ranked based on the prioritization criteria found Exhibit 2 Appendix 2-A, Table 5.3-2. This ensures that investments are consistently prioritized and selected based on providing reliable and sustainable energy services.
- Stakeholder Review: Investment candidates are internally reviewed to ensure that there is alignment with organizational goals and validates that scopes, schedules and costs are prudent and reasonable. Customer feedback is sought through a variety of mechanisms and provides valuable insight into the customers' perspective.
- Review and adjustment: The prioritization process is not static; it undergoes review and adjustment based on evolving conditions, emerging technologies, and changes in business objectives.
- Transparent communication: SNC maintains communication with stakeholders, including customers and regulators, regarding the prioritization of its capital investments.

b) SNC has undertaken a thorough process to ensure that the asset condition assessment and asset management system of the two pre-existing service areas have been harmonized effectively to facilitate proper prioritization. This validation process involved several key steps:

- Comprehensive data collection and integration: All relevant data pertaining to the assets in both service territories was systematically collected and compiled. This included information on asset condition, performance history, maintenance schedules, and any pertinent historical records.
- Standardization of assessment criteria: SNC established consistent criteria for assessing asset condition across both service areas. This ensures that evaluations were conducted using a common set of benchmarks, allowing for accurate comparison and prioritization.
- Verification through field inspections: Field inspections were carried out to physically verify the condition of assets from both service areas.
- Analytics and tools: SNC employed the same data collection tools, analytical tools, and software processes to analyze the collected data and assess the condition of the assets.

- Stakeholder input and review: Feedback and insights from internal stakeholders, including asset managers, engineers, and field personnel, were sought, and incorporated into the assessment process. This ensured that the perspectives of those directly involved in the assessment process were considered.
- Monitoring and feedback: The assets in both service areas are assessed on the same schedule and feedback from field staff is incorporated into future assessments. This ensures any adjustments and refinements to the processes are made consistently, enabling ongoing harmonization.

2-Staff-11

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.2.1.1.2 Mission, Vison, Values and Goals, page 7, .PDF page 105

Preamble:

Regarding labour and material resources allocation, Synergy North states:

"In the case of this DSP, SNC has planned these investments over a five-year term. This allows SNC to allocate both labour and material resources in a cost- effective and efficient manner to achieve its corporate goals and the evolving needs of its customers; ultimately managing the impacts of these investments on customer rates."

Question(s):

a) How does Synergy North plan to ensure that customers in each service area receive comparably reliable service?
b) Please describe any differences between the two service areas (e.g., population density, climate, topography, surface geology, access constraints) that present challenges in achieving these outcomes.

SNC Response:

a) SNC employs a structured approach to ensure that customers in each service area receive comparable benefits from the planned investments. As described in 2-Staff-10, SNC has fully integrated its Kenora service territory into its planning process through identifying needs in each service area, considering asset condition and projected future demands. This data driven process forms the basis for prioritizing investments and resource allocation.

SNC actively seeks input from customers and stakeholders to understand the upcoming and ongoing needs and concerns specific to the service area.

Specific performance measures are studied (worst performing feeder) and this is conducted on every circuit for both service territories.

This is a cyclical process that occurs regularly to ensure that investments remain aligned with the evolving demands in each service area.

b) Below is a synopsis of the differences between the two service areas.

The Kenora service area is more compact as compared to Thunder Bay. Kenora has 57 customers per circuit km of lines, while Thunder Bay has 44 customers per circuit km of lines.

Thunder Bay has a large rural area in addition to the urban area; there is no equivalent rural area in Kenora.

Thunder Bay Urban – 90% of Services, 31% of land area.

Thunder Bay Rural – 10% of Services, 69% of land area.

The Kenora service area includes services and infrastructure on Coney Island, Harris Island, Tooles Island, Scott Island, Treasure Island and Fortunes Island, which are not accessible by road and require the use of a ferry/barge.

Kenora has a more continental climate than Thunder Bay; on average, it experiences larger temperature swings, colder winters, and hotter summers.

2-STAFF-12

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.2.1. 2 Capital Investment Overview, page 7, .PDF page 105

Preamble:

Table 5.2-1 of the DSP shows historical actual and forecast capital expenditures.

Question(s):

a) Please explain what drove the step changes in System Renewal capital spending in 2021 & 2022 and explain why those step changes form the new base level of System Renewal spending going forward into the forecast period.
b) Please explain what drove the step change in System O&M costs in 2022, and why that step change forms the new base level of O&M spending going forward into the forecast period.

SNC Response:

a) The step changes in System Renewal capital spending have been discussed in Exhibit 2, Attachment 2–A, Section 5.4.1.2.2 of the DSP on Page 104. There SNC discussed that in 2020 it took decisive steps to defer a portion of its capital budget and ended the year under budget by $1,316K. Projects were deferred as a result of SNC's cashflow concerns and because they posed an increased risk of COVID-19 transmission due to the nature of the work (i.e. Staff were required to work near one another) but could be safely deferred without putting the system at significant risk. This deferral of work gives the impression that there was a step change in 2021, when the level of spending was aligned with the planned budgets (See Page 99, Table 5.4-1 Historical Capital Expenditure and System O&M). In 2022, with the major impacts of resource availability due to COVID-19 behind the utility, SNC embarked on completing work that it had deferred.
b) The "step" increase in System O&M spending is primarily due to the increase in tree trimming in response to safety and reliability issues. This is further detailed in Exhibit 4, Section 4.3.3.5 Vegetation Management and in the Vegetation Management Plan in Attachment 4-C. Excluding this additional spending the values would have been as per below.

TABLE 2-1: IMPACT OF VEGETATION MANAGEMENT ON SYSTEM O&M

	2022	2023	2024
System O&M			
As Filed	$ 11,359,433	$ 11,252,770	$ 11,778,893
Incremental Tree Trimming	$ 1,350,000	$ 1,350,000	$ 1,350,000
OM&A without Incremental Tree Trimming	$ 10,009,433	$ 9,902,770	$ 10,428,893

2-STAFF-13

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.2.1.2.2 System Renewal, page 9-10, .PDF page 107-106

Preamble:

Regarding asset replacements in 4kV voltage conversion, Synergy North states

"The 4kV Conversion program represents the most significant program in the system renewal category (See Appendix H for current program justifications). It has accounted for approximately 49% of asset replacements in the historical period from 2017-2022 (by dollar value, see Figure 5.2-4)."

On page 10, Synergy North states:

"These costs are between five and nine times higher than the expected inflated values over this period. Using these estimated costs, without the remaining line items, SNC estimates a net present cost of $33M (at a 2% CPI) to rebuild the seven remaining 4kV substations during this filing period."

Question(s):

a) Figure 5.2-4 shows that 4kV conversions comprise half of Synergy North's forecast test period Renewal spending. Has Synergy North developed a business case demonstrating the ongoing cost-effectiveness of this program compared to other candidate renewal projects?
   i. If yes, please provide the business case.
   ii. If no, please explain how Synergy North determined that this initiative was the most cost-effective target for renewal spending.

b) Given this level of cost escalation, does this program still make economic sense? In other words, do the business drivers still justify the ongoing project at these capital cost levels?

i) If yes, please show the quantified revised economic analysis.

SNC Response:

a) SNC submitted documentation regarding its proposal to undertake 4kV conversions in Thunder Bay Hydro Electricity Distribution Inc (TBHEDI) Cost of Service Application (EB-2012-0167) and has attached, Attachment 1-4 :4kV Conversion for reference. Although this is not a formal business case, this was the basis for proceeding with the 4kV conversion program. SNC has recalculated the value of this case and updated the cost estimates to 2023 values to confirm the economic viability of the program of decommissioning versus replacing substations. (See Table 2-2 for the updated estimated costs). A revenue requirement analysis was completed and is included in the response to 1-CCC-7.

TABLE 2-2: 4KV SUBSTATION REPLACEMENT ESTIMATE 2013 VS. 2023

Distribution Station Component	Estimated Cost to replace components in 2013	Estimated Cost to replace components in 2023
4MVA, 24.94kV/4.16kV, Oil Immersed Power Transformer (Qty 2)	$250,000	$1,648,000
4kV, 1200A Breaker Lineup (8 Breakers/Substation Average)	$310,000	$3,500,000
Total	**$560,000**	**$5,148,000**

Additional Costs included in the 2013 business case were DC supply components, power and Instrument transformers, protective relays, ground and test device, power quality meters, current transformers, infrared viewing ports, auxiliary substation components, civil work, engineering and design and labour trucking and additional materials. They have not been considered in the 2023 comparison of replacing the substations.

b) In 2013, the program included 14 substations; in 2023, the analysis uses only the 7 remaining substations.

The total of 7 stations must be replaced from 2023 to 2028. The present value of their replacement at 2% CPI equals	$33,683,548
The total net present value to decommission 7 remaining substations at 2% CPI (57,888 per station)	($370,839)
The total avoided cost of replacing 7 stations	$33,312,709 or rounded as $33.3 Million

The cost escalation of the replacement of the substation transformer (from $250,000 in 2013 to $1,648,000 in 2023) and the replacement of the switchgear (from $310,000 in 2013 to $3,500,000 in 2023) has improved the business case for 4kV conversions. Converting the voltage allows SNC to decommission the substation rather than incur the capital costs of replacing the substations, therefore avoiding the $33.3M of costs. In the next DSP period of 5 years, 60% of the assets in the areas that are scheduled for 4kV conversion would require replacement due to asset condition, regardless of the substation replacement driver. Further information on the savings associated with the conversion can be found in SNC answer to 1-CCC-7.

2-STAFF-14

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.2.1.2.2 System Renewal, page 10, .PDF page 108

Preamble:

Regarding 4kV Conversion program, Synergy North states:

“Over the five-year forecast period SNC plans to invest in removing the remainder of the installed 4kV infrastructure, including wood poles, transformers, cables, substation breakers and substation transformers. The forecasted expenditure for this program is approximately $27M.”

Question(s):

a) Is this amount cumulative spending from the original project initiation to completion, or just during the test period?

SNC Response:

a) The $27M amount of spending on 4kV Conversion Program is cumulative for the projects in this program for the DSP period from 2024-2028. It does not include spending from the original project initiation.

2-Staff-15

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.2.1.2.2 System Renewal, page 10, .PDF page 108

Ref 2: Exhibit 2, Attachment 2–A, Section 5.4.1.3.1 System Access, page 109, .PDF page 207

Preamble:

Regarding Overhead Renewal program, Synergy North states:

"The Overhead Renewal program includes planned expenditures of $13M over the forecast period. This includes planned renewal efforts on overhead systems (poles, transformers, switches, etc.) that fall outside the 4kV conversion projects."

Regarding joint-use process, Synergy North states:

"At 27% Recoverable work represents the second largest driver within this category. Recoverable work consists of modifications to existing customer connections and make-ready work for third parties. Most of this work stems from asset replacements driven through the joint-use process and is expected to stabilize over the forecast period with costs rising with inflation."

Question(s):

a) What proportion of the existing 4kV wood poles are in end-of-life condition (i.e., poor or very poor), and what proportion are still in serviceable condition (fair, good or very good)?
b) Does Synergy North count the poles replaced during the 4kV conversion project as part of the wood pole replacement program, or are these in addition to the wood pole replacement program?
c) Please provide the total number of poles replaced in each year of the historical period and expected to be replaced in each of the test period for all reasons.

SNC Response:

a) Please see Table 2-3 below.

TABLE 2-3: 4KV WOOD POLE CONDITION - 2022

Health	Very Poor	Poor	Fair	Good	Very Good
Quantity	2	128	451	391	409

SNC considers that very poor and poor poles are those that need to be replaced immediately, i.e. as soon as reasonably possible. Fair poles are those that are scheduled for replacement in the next 5 years, as the poles in this category are expected to age and degrade to Poor in the next 5 years.

b) SNC counts poles in the 4kV conversions as part of its wood pole replacement program.
c) Please see Table 2-4 below.

TABLE 2-4: POLES REPLACED FOR ALL REASONS 2017-2024

Year	Quantity
2017	473
2018	438
2019	539
2020	637
2021	563
2022	609
2023	405
2024	520

2-STAFF-16

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.2.1.3 Key Changes since Last Filing, page 12, .PDF page 110

Preamble:

Regarding merger of Thunder Bay Hydro and Kenora Hydro, Synergy North states: "Merger of TBHEDI and KHECL - In 2019 Thunder Bay Hydro Electricity Distribution Inc. and Kenora Hydro Electricity Corporation Ltd. merged to form Synergy North Corporation. An important objective of which was the creation of opportunities for efficiencies through economies of scale, innovation, realizing competitive advantages throughout the service territories and the sharing of best practices across all facets of the business." [footnote omitted]

Question(s):

a) Please describe and quantify any examples of the listed efficiencies that have either already been implemented or that will be implemented and are forecast to reduce SNC's revenue requirement over the test period.

SNC Response:

a) Please see SNC response to 1-STAFF-4, 1-SEC-7, 1-CCC-13, and 1-AMPCO-4 for details on savings generated as a result of the merger. The total reduction in 2024 revenue requirement as a result of these changes is $888,860 ($884,848 in OM&A reduction, $4,012 in return on capital). Further as discussed in 1-CCC-13, as a result of the review of Kenora's capital, certain fleet assets were transferred from the Thunder Bay yard to Kenora including a single bucket truck, a backhoe with a rock breaker, an F250 Crew Cab with a topper, and a pole trailer. In addition, the adoption of line construction and engineering best practices to the Kenora territory, built off Thunder Bay's extensive experience with pole line rebuilds, has resulted in efficiency improvements. SNC also provided significant engineering services as part of the make ready work required in Kenora as part of the Tbaytel fibre connection program. This work would have been outsourced at higher cost had the merger not occurred.

2-Staff-17

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.2.1.3 Key Changes since Last Filing, page 12, .PDF page 110

Preamble:

Regarding Asset Condition Assessment, Synergy North states:

"SNC has continued to utilize the Asset Condition Assessment models provided by Kinectrics from its 2016 DSP filing. However, SNC staff have updated the models from field collected data rather than obtaining consultant services during this rate filing."

Question(s):

a) Please list any assets or asset classes for which Synergy North's field collected data varies from the default Kinectrics expected service life or age vs. condition values for similar assets and asset classes and quantify the variances.

SNC Response:

a) SNC's field collected data has not varied from the default Kinectrics expected service life from 2016.

2-Staff-18

Ref 1: Exhibit 2, Attachment 2–A, Section 5.2.2.1 Customers, page 18-19, .PDF

page 116-117

Preamble:

Regarding incorporation of customer feedback, Synergy North states:

“Customer have consistently told us that they prefer a proactive approach to our capital program, renewing equipment prior to failure in order to avoid longer outages times.”

“Customer chose an option which suggested we spend more on our vegetation program to ensure we are compliant with industry standards.

The majority of customer chose to spend between $1.00 and 1.50 per bill at the speed described in the survey, as opposed to the other choices presented.”

Furthermore, the customer survey results for CAPEX investment found that

- 42% of respondents selected to keep rates low even if reliability decreases,
- 46% selected to maintain the current investment strategy, and
- 12% of respondents selected that they would accept higher rates to increase system reliability.

Question(s):

a) When framing the associated questions, did Synergy North inform its customers that increasing the proactivity of its capital program should be expected to correspondingly increase its cost of service, an outcome which is opposed to the fourth consideration listed here (i.e., lower costs, which is the perennially most important consideration from a customer perspective).

b) Please reconcile the findings shown in this figure with Synergy North's claim in Fig 5.2-7 that "Customers have consistently told us that they prefer a proactive approach to our capital program, renewing equipment prior to failure in order to avoid longer outage times".

SNC Response:

a) Yes, SNC informed customers during the engagement that proactive programming would cost them more for proactive capital replacement. This is referenced In Phase 1 of our customer engagement (Exhibit 1, Attachment 1-K, Q5 page 347/387 and Q10 page 352/387 in Survey Responses_Report Phase 1 and Q9 page 368/387 in Survey Responses_Report Phase 2).

b) Q5 in Survey 1 asked "Tell us what is most important to you as a SYNERGY NORTH customer".

Q10 in Survey 1 asked "*Climate change is affecting the severity of storms. Power outages due to weather related events can sometimes be avoided by replacing aging infrastructure before it fails. Should SYNERGY NORTH proactively replace aging infrastructure?"*

Q9 in Survey 2 asked*, "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?"*

During the Cost of Service application in 2017, Thunder Bay Hydro engaged its customers and filed responses to their engagement. Question 5 asked "*With regards to projects focused on replacing aging equipment in poor conditions, which of the following statement best represents your point of view?"* 52.37% responded that "Thunder Bay Hydro should invest what it takes to replace the systems aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years." See Attachment 2-1: Customer Survey. Again, customers responded in our recent customer survey when asked in Q10 of Survey 1 that 83% support proactive replacement to maintain reliability. For 2024 COS the customer responses continue to support SNC's strategy.

The response to Q5 in Survey 1 where SNC asked "*Tell us what is most important to you as a SYNERGY NORTH customer*: 60% answered "Maintaining SYNERGY NORTH's current investment strategy" or "Higher distribution rates increasing system reliability."

Where Q10 in Survey 1 asked about Climate change affecting the severity of storms. Power outages due to weather-related events can sometimes be avoided by replacing aging infrastructure before it fails. Should SYNERGY NORTH proactively replace aging infrastructure? 83% of customers responded that "Replace proactively to maintain reliability which can often cost more upfront."

Q9 in Survey 2 provided the following information to customers: 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?" Customers responded with 66.2% Yes, I support a balanced capital spending plan, and 26.7% responded that I do not support a balanced spending plan, but understand it is necessary.

With respect to the consistency of feedback regarding the need to be proactive, in the Cost of Service application in 2017, Thunder Bay Hydro engaged its customers and filed responses to their engagement. Question 5 asked "*With regards to projects focused on replacing aging equipment in poor conditions, which of the following statement best represents your point of view?"* 52.37% responded that "Thunder Bay Hydro should invest what it takes to replace the systems aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years." See Attachment 2-1: Customer Survey. Again, customers responded in our recent customer survey when asked in Q10 of Survey 1 that 83% support proactive replacement to maintain reliability. For 2024 COS the customer responses continue to support SNC's strategy.

Furthermore, a proactive replacement of assets allows the corporation to properly manage the overall cost of asset replacement due to economies of scale, proper inventory management and overall reduction of overtime and callouts.

2-STAFF-19

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.2.2 Coordinated Planning with Third Parties, page 17, .PDF page 115

Ref 2: Exhibit 2, Attachment 2–A, Section 5.3.1 Planning Process, page 47, .PDF page 145

Preamble:

Regarding customer feedback from the "Have Your Say" survey, Synergy North states: "SNC customers asked that we prioritize affordability and keep costs down. This understanding, as evidenced by the survey results, was a major factor in defining our application."

Regarding customer engagement activities in 2022 and 2023, Synergy North states: "SNC conducted a comprehensive customer engagement planning survey that provided valuable input for the development of scenarios including investment envelopes and preferred outcomes. Approximately 70% of distribution customers prioritized reasonable rates and reliable service and supported maintaining the current level of investment."

Question(s):

a) Please explain how customer preferences related to affordability and rates have been taken into account when targeting investments related to system reliability.

SNC Response:

a) Customer Preferences related to affordability and rates have been considered for all projects planned for investment using the prioritization criteria and weighting listed in Table 5.3-2 of the DSP (reproduced below). Further details regarding the application of the criteria to projects (which include system reliability investments) can be found on Attachment 2-A, Section 5.4.2.1.

The planning process is rooted in customer-centric thinking, recognizing that meeting customer needs and expectations is a strategic part of the asset management process (AMP). SNC engages customers through various channels, allowing them to stay informed about the process and progress. Assessing customer needs is a key input into the AMP, and customer feedback plays a crucial role in determining the pacing of capital plans.

SNC employs a structured workflow for planned and demand-driven work programs, aiming to minimize disruptions caused by fluctuating demand. This process allocates specific time for customer engagement and feedback, ensuring that customers are informed of projects and outage schedules. Additionally, they coordinate activities with third parties and other ongoing work, while also securing necessary resources. This approach ensures that work is scheduled during optimal site conditions. SNC's resource strategy emphasizes safety and efficiency, aiming to deliver capital programs within approved expenditure levels while maintaining commitments to customers. Internal resources are allocated based on program requirements, utilizing overtime and contract resources as needed to manage conflicting priorities. To address seasonal construction fluctuations and demand variability, SNC maintains strategic relationships along the supply chain to ensure a steady availability of resources.

Furthermore, SNC's system access programs are designed to meet customer-driven demands while considering cost reduction and risk mitigation strategies. This includes evaluating options such as overhead versus underground installations and ensuring appropriately sized transformers. SNC diligently monitors system renewal spending, with the objective of maintaining a safe and reliable electricity supply while preventing retail rates from becoming unaffordable. Investments are optimized based on the best available data from the AMP and customer feedback, and staffing levels are balanced accordingly to efficiently execute planned work. In addition, system service investments work in tandem with system renewal investments to enhance operational flexibility and improve system visibility, ultimately meeting customers' performance expectations for reliability and power quality.

Table 5.3-2 Prioritization Criteria

Criteria	Description	Weight (A)
Health & Safety	Risk of safety incidents sustained by SNC's staff, contractor, or general public, living, and working in the vicinity of the utility's equipment.	41.1
Environmental Impact	Risk of unplanned and uncontrolled release of a hazardous substance (e.g., PCB Spills) or the consequences of climate change, vegetation contact, flooding.	22.9
Regulatory/Legal Compliance	Assesses the degree to which project, service, or product is compliant with regulations and legal obligations.	12.3
Customer Preference	Preferred impact of project, service, or product to customer requirements.	8.4
Asset Performance	Project, service, or product replaces substandard equipment or otherwise improves the operations and maintenance practices on the system thereby addressing asset health concerns, premature failures, etc.	6.3
Operational Efficiency	Project, service, or product that otherwise improves or avoids the following: • Reduces operating expenses; • Avoids future capital costs; • Coordinates with other programs; or • Decreases liability or increases without action.	4.7
System Reliability	Electrical service continuity: translating it into customer interruption statistics and determining customer base affected.	4.2

2-Staff-20

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.2.2.3 Regional Planning Process, page 23, .PDF page 121

Ref 2: Exhibit 2, Attachment 2-A, Section 5.4.2 Justifying Capital Expenditures, page 124-125, .PDF page 222-223

Preamble:

Regarding Kenora MTS's capacity, Synergy North states:

"There is a window of opportunity between today and 2030 when the Kenora MTS capacity need arises to leverage learnings from the York Pilot and further refine NWAs for Kenora MTS."

Regarding load growth, Synergy North states:

"However, as previously discussed in Section 5.3.2.1.4, SNC is anticipating some capacity constraints in its Kenora service territory (following the forecast period) for which traditional investments will be under consideration."

Question(s):

a) Is the probability that the need for capacity in Kenora will occur after 2030 greater than the probability that it will occur before 2030?
b) What are the key demand growth drivers?
c) Why will there be capacity constraints with little load growth?

SNC response:

a) SNC created the load forecast for Kenora MTS in conjunction with IESO for the Northwest IRRP (Exhibit 2, Attachment 2-A, Appendix B of the DSP) and in conjunction with HONI for the Northwest RPP (Exhibit 2, Attachment 2-A, Appendix J), the probability of the need occurring before 2030 is largely dependent on the development of several large infrastructure projects in this distribution territory and their funding by the government. SNC has provided high level cost estimates to these development projects but has not received signed confirmation from the project proponents. If these development projects do go ahead, it is probable that the need will occur before 2030. However, if these development projects do not go forward, it is likely that the capacity will be reached after 2030.
b) SNC performed a multi-linear regression analysis to determine load growth correlated to economic and weather-related factors. The details of which are contained in the IRRP Appendices (Appendix B). In addition, key growth drivers are residential and recreational property development as well as general service development. Kenora is a hub for social and medical services for the far north, and SNC continues to receive interest from Indigenous Groups for development of support infrastructure. 2-Staff-27 details the number of connections that SNC has received in Kenora since the merger.
c) Due to the rating of the substation in Kenora (Limited-Time-Rating of 23.4MW) and the 2022 peak loading (just under 20MW) a small increase in growth (1.25%) equates to approximately 0.2MW to 0.3MW of additional load annually. Between this incremental increase and the available capacity of 4MW, the maximum capacity of the station is readily exceeded in 9 years.

2-STAFF-21

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.2.2.7 Summary of Effects on the DSP, page 37, .PDF page 135

Preamble:

Regarding SAIDI and SAIFI improvements, Synergy North states:

"SNC customers have experienced an average annual improvement in SAIDI (all causes) of 12%, and average improvement in SAIFI (all causes) of 6% over the historical period."

Question(s):

a) Is Synergy North able to quantify the reliability improvements in terms SAIDI and SAIFI being delivered by specific System Service investments?

   If yes, please provide details.

b) Do these experienced reliability improvements enable Synergy North to pace its capital investments more slowly than planned while still maintaining historical levels of reliability?

   If no, please explain why not.

SNC response:

a) SNC is unable to quantify the reliability improvement in terms of SAIDI and SAIFI delivered specifically by System Service investments, as SNC did not track improvements related to the investments. It's important to note that the correlation between system maintenance activities and electricity reliability statistics is not absolute as reliability can be influenced by factors such as weather events, changes in demand, and external factors beyond the utility's control. Additionally, SNC also undertook several capital and OM&A initiatives that would have had an impact on improvements in reliability such as asset replacements and vegetation management.
b) SNC has made informed decisions regarding the volume and timing of replacements in an effort to achieve the minimum level of intervention required to maintain the system. The prioritization matrix (Table 5.4-19 in Exhibit 2, Attachment 2-A page 230 of the pdf) outlines how SNC has scored

each program based on its drivers. These programs are paced based on their primary drivers, which in many cases is failure risk (focusing on assets in poor health), with reliability improvements being a secondary driver. While it may be possible to pace capital investments more slowly it would result in increased risk of asset failure.

2-Staff-22

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.2.2.7 Summary of Effects on the DSP, page 37, .PDF page 135

Preamble:

Regarding asset management, Synergy North states:

"SNC uses the following asset management metric to monitor the progress of the DSP annually:

Financial performance measured as plan vs. actual expenditures (in percent)

a) Over Expenditure >100%
b) Under Expenditure <100%."

Question(s):

a) Are over and under expenditures correlated against value produced? In other words, does Synergy North report if the planned scope of work was completed for more or less cost than planned, or is the focus solely on the amount spent without consideration of the value produced for ratepayers?

SNC response:

a) SNC provided this metric to monitor the progress of the DSP in its last submission to the OEB, (EB-2016-0105). This metric was included in TBHEDI's and SNC's scorecard metrics which are available publicly. In the absence of direction from the OEB or a consistent metric used by other utilities, and to maintain consistency in its reporting throughout the period, SNC chose to follow the metric detailed above. While the metric only captures financial performance, SNC ensures customer value by maintaining rigorous oversight over its program portfolio and improvements to the project delivery process have led to improved reporting and forecasting capabilities. Internal meetings are held regularly to review performance and adjust forecasts; this includes a review of system access and O&M trends to evaluate opportunities and risks. Detailed work performance reporting is provided on a bi-weekly basis and highlights information on schedule, cost, and scope.

As the largest forecast expenditure, it is vital that SNC remain diligent in monitoring system renewal spending. This category has the objective of maintaining the safe and reliable supply of electricity to SNC's customers, while keeping retail rates from escalating beyond their affordability. To execute planned work efficiently, over the forecast period SNC has optimized the pacing of its investments based on the best available data from the asset management process and customer feedback; and will balance staffing levels in accordance with this planned level of work.

2-Staff-23

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.3.1.2.2 Asset Removal Data, page 42-43, .PDF page 140-141

Preamble:

Regarding the data collection on the driver for replacement of major asset categories, Synergy North states:

"Also in 2019, SNC began to collect data on the driver for replacement for its major asset categories including but not limited to, poles, switches, cables, and transformers. The intent of the results was again to inform the ACA with objective information regarding the age at which assets fail."

Regarding the geospatial asset data, Synergy North states:

"SNC has been integrating the results of the ACA with the geospatial asset data since 2018."

Question(s):

a) Does Synergy North record the asset vintage/achieved lifespan at the time of replacement when categorizing the replacement driver?
b) Does the geospatial dataset include vintage/year of installation for individual assets?

SNC Response:

a) Yes, asset vintage is recorded at the time of replacement.
b) Yes, the geospatial dataset includes vintage/year of installation for individual assets.

2-Staff-24

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.3.3.4.1 System Renewal Optimization and Budget Alignment, page 93, .PDF page 191

Preamble:

Regarding the system renewal program, Synergy North states:

"SNC's system renewal program is driven from the outcome of the ACA which provides a levelized plan for assets in poor condition. System renewal efforts focus on assets requiring renewal in voltage conversion areas."

Question(s):

a) Does Synergy North map its ACA to its reliability performance targets when prioritizing renewal projects, or does Health & Safety typically drive asset replacements, regardless of potential system reliability outcomes? Please explain.

SNC response:

a) SNC does not map its ACA to reliability performance targets. Renewal projects are prioritized using the program prioritization process found in Exhibit 2 Appendix 2-A, Section 5.4.2.1, and Appendix K. The criteria for project prioritization include the following:

- Health and Safety – Risks of safety incidents sustained by SNC staff, contractors, or the general public.
- Environmental Impact – Risks of hazardous spills, climate change, or vegetations contacts.
- Regulatory/Legal Compliance – Assessing the degree to which a project is compliant with applicable regulatory/legal obligations.
- Customer Preference – Determining the impact of a project or service to customer requirements.
- Asset Performance – Assessing whether a project or services addresses or improves system performance by correcting poor performing assets.
- Operational Efficiency – Gauging whether a project or service improves operating performance and/or avoids future capital.
- System Reliability – Translating interruption statistics into improved service continuity.

System reliability is further categorized by the following table:

TABLE 2-5: SCORING METHODOLOGY FOR SYSTEM RELIABILITY IMPACTS

System Reliability	Scoring (B)	Prioritization Score (C)
Sustained interruption of > 12.5 MW of distribution load (>2,500 residential customers)	20	4.2%
Sustained interruption of 4.5-12.5 MW of distribution load (900-2,500 residential customers)	15	3.2%
Sustained interruption of 1.5-4.5 MW of distribution load (300-900 residential customers)	10	2.1%
Sustained interruption of <1.5 MW of distribution load (100-300 residential customers)	5	1.1%
No impact on reliability of distribution.	0	0.0%

2-Staff-25

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.4.1.1 Summary of Changes to Capital Programs, page 100, .PDF page 198

Preamble:

Regarding summary of changes of 4kV conversion capital program, Synergy North states:

"Program has been paced to allow for conversions to be completed by the end of this DSP. See Appendix H: Material Investment Report – Voltage Conversions for further details."

Question(s):

a) Following completion of the 4 kV conversion program in this test period, does Synergy North anticipate that its Renewal spending will decrease significantly in the subsequent test period, given that the 4 kV conversion program presently represents almost half of its renewal spending?

SNC response:

a) Because we have deferred other areas as flagged for action, SNC does not anticipate that renewal spending will decrease significantly in the subsequent test period. SNC uses the output of the ACA and the flagged for action plan to determine the target quantity of assets requiring intervention annually. SNC is anticipating asset renewal to remain at a consistent level following the completion of the 4kV conversion program. SNC's planning and decision-making processes are by necessity nuanced; however, this DSP has been influenced by customer mandates surrounding affordability. As such, SNC has deferred work in programs whereby the increased risk of doing so will not jeopardize the near-term reliability of the system. SNC expects to shift focus to increase renewal of infrastructure in these programs when there is a decrease in 4kV conversion spending. The programs that have had quantities of assets deferred (i.e. from the Flagged for Action quantity) includes assets such as underground cable, vault transformers and pad mounted transformers.

2-STAFF-26

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.4.2 Justifying Capital Expenditures, page 126, .PDF page 224

Preamble:

Regarding system renewal trend, Synergy North states:

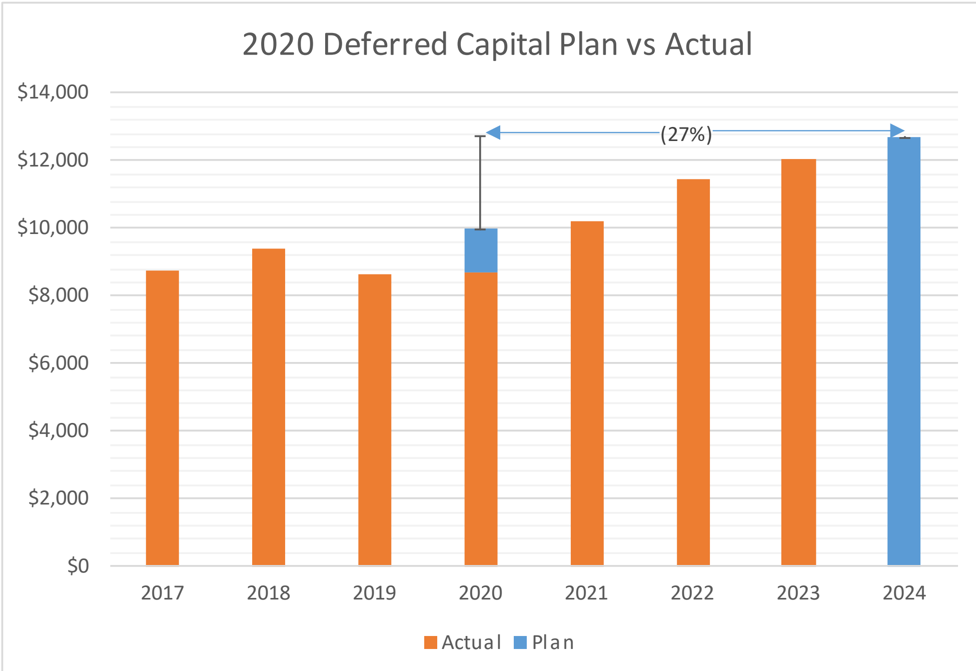
“It is apparent from Figure 5.4-13 that system renewal trend increases through the test year to 2025, then stabilizes through to the end of the forecast period. These increases are mainly due to market volatility and significant increases in material pricing.”

Question(s):

a) Synergy North indicates that the renewal trend increases through to 2025 are "mainly due to market volatility and significant increases in material pricing". Please confirm that Figure 5.4-13 indicates that Renewal spending is projected to increase by approximately 50% from 2020 to 2024. If confirmed, please itemize the market volatility and material pricing increases that result in this 50% spending increase.

SNC response:

a) Confirmed. The increase in renewal spending is approximately 50% from 2020 actual to 2024 planned. As discussed in 2-Staff-12, SNC reduced its capital expenditure in 2020 by $1.316 million. Had SNC not deferred spending in that year, the increase in spending between 2020 and 2024 would be approximately 27%. The following figure illustrates the plan vs actual system renewal spending.



Please see the following excerpt from page 48 of Exhibit 1, Section 1.4.16.4 regarding the rise in prices that have influenced the proposed increase in projected spending:

1.4.16.4 Global Inflation

Canada's annual inflation rate in 2022 was 6.8%, the highest level seen since 1991. Over the last few years SNC has experienced significant inflationary increases on materials, goods, and services specifically related to its capital and operating costs. Some examples of cost increases SNC has experienced are the following:

- There has been a 31% increase in the price of diesel fuel and 20% increase in gasoline fuel costs from 2021 to 2022 significantly impacting SNC's fleet costs;
- The cost for Pad mount transformers has increased by an average of 75% on the most common units ordered by SNC from 2022 to 2023 due to the significant cost increase of steel;
- The price of wood poles has increased by 17% from 2022 to 2023;
- Wire and Cable costs, manufactured out of copper and aluminum have increased by an average of 60% from 2021 to 2022.

2-Staff-27

Rate Base

Ref 1: Exhibit 2, Appendix B: IESO NORTHWEST IRRP, page 42, .PDF page 290

Preamble:

Regarding Kenora MTS, Synergy North states:

"Synergy North has received inquiries from potential customers seeking new connections, including a new 4 MW project, but no formal agreements have been finalized. While these projects have not been included in the forecast, a relatively high annual growth rate of 1.25% was applied to account for the high degree of development interest."

Question(s):

a) What (magnitude, type) new load has connected in the Kenora area since the merger?

SNC response:

a) Please see Table 2-6 below.

Table 2-6: New Loads in Kenora Service Territory 2019-2023

	2019	2020	2021	2022	2023 (YTD)
Number of new General Service Customers	6	4	6	1	6
Total Peak Load as provided by the Customer (kVA)	1159	567	1059	45	1613

2-Staff-28

Rate Base

Ref 1: Exhibit 2, Material Investment Report, System Renewal, page 10, .PDF page 470

Preamble:

Regarding wood pole removal, Synergy North provides Figure 2-5 Wood Pole Removal Statistics 2019-2022.

Question(s):

a) Does this chart only cover poles replaced under the pole replacement programs or does it include all poles replaced for any reason?

- If the former, please provide a similar chart for all poles replaced for any reason.

SNC response:

a) This chart includes poles replaced for any reason.

2-Staff-29

Rate Base

Ref 1: Exhibit 2, Material Investment Report, System Renewal, Section 2 Investment Need, page 9, .PDF page 511

Preamble:

Figure 2-4 Padmounted Transformer Removal Statistics 2019-2022 shows the reasons these assets were removed from service.

Question(s):

a) Which category represents 0% of removals (PCB Related Replacement or Electrical Failure)?
b) Which category represents 1% of removals (Relocations or System Health Improvements)?

SNC response:

a) PCB related replacement.
b) Relocations.

2-Staff-30

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Section 5.4.1 Capital Expenditure Summary, page 104-105, .PDF page 202-203

Preamble:

Regarding General Plant Net Variances Synergy North states:

"2017 – 29% ($375k) Under Budget

Prior to the merger of Kenora Hydro and Thunder Bay Hydro, Kenora was approved for a 2017 Board Approved Proxy of $150,000 in rolling stock and

$155,000 in building improvements. These expenditures were not realized in 2017 as the building improvements were made in 2011 and 2012 and the single bucket truck in rolling stock was purchased in 2011.

2018 – 35% (584k) Under Budget

Computer equipment was budgeted in the DSP to cost $307,200 and $114,127 was spent due to the deferral of the IBM iSeries server replacements to 2019. Like the 2017 General Plant variance explanation, $316,000 was budgeted in Kenora as a 2017 Board Approved Proxy for rolling stock and building improvements and only $20,000 was spent on tools."

Question(s):

a) Please provide clarification regarding the 2017 variance. It is not clear how the expenditures were undertaken in 2011 when the Board only approved the budget in 2017?
b) For the 2018 variance values, please confirm whether replacements were deferred due to the merger and whether the items planned for replacement in 2018 were acquired in the subsequent years?

SNC Response:

a) The total capital budget approved by the OEB for Kenora in 2011 was used as a proxy for the 2017 year. The total 2011 capital budget included line items specifically for rolling stock and building improvements. These specific line items contribute to the total annual capital proxy budget amount but are historical purchases.
b) The decision to defer replacements was a KHEDI management decision and not as a result of the merger. The Proxy capital was subsequently added add merger to SNCs future capital Plan, however management did not make any further adjustment to account for the 2018 underspend. SNC confirms that the IBM iSeries server deferred in 2018 was purchased and installed in 2019 and that the deferral was not as a result of the merger.

2-Staff-31

Rate Base

Ref 1: Exhibit 2, Attachment 2 – A, FINO Strategic Framework, page 10, .PDF page 408

Preamble:

Regarding Feeder Capacity for Generation and Load Connections, Synergy North states:

"Medium and Large Generators have the telemetry back to Synergy North's control room to allow the control operators to disable and enable the generators to feed energy onto the grid. This is the basis of a FINO, and Synergy North has experience in doing so for operational purposes. The evolution is to potentially utilize this existing capacity to create demand response programming."

Question(s):

a) How many medium and large generators are controlled by Synergy North at present?
b) Please also describe the technology type of the distributed generation connected to Synergy North's system (solar, wind, battery, etc.).

SNC response:

a) SNC presently has 6 medium sized generators connected to its distribution network. SNC has the ability to remotely disable/enable these generators as necessary (with the exception of one location that does not have that capability). By definition, large generators are >10MW and our largest is 8.9MW, so SNC has zero large generators.

b) The technology types of medium generators that are connected to SNC's system vary, there are 2 solar, 2 natural gas cogeneration and 2 bio-gas generators. Page 8 of Appendix A of the DSP "Renewable Energy Generation Plan 2023-2028" provides micro (<= 10kW) to large (>10MW) renewable and non-renewable connections and their load.

2-Staff-32

Rate Base

Ref 1: Exhibit 2, Attachment 2–A, Material Investment Report Investment Category: System Access Capital Recoverable, page 2, .PDF page 441

Preamble:

Please refer to the tables on page 2 of the Material Investment Report for Capital Recoverable, System Access.

Question(s):

a) What types of costs are borne by Synergy North under the System Access category that are not recoverable by the customer?
b) Is there a pattern to infrastructure damage due to motor vehicle accidents, such as geographic area, installation standard, sight lines, etc.
c) What steps has Synergy North taken to prevent damage to its equipment by motor vehicle accidents, for example, installation of bollards or equipment setbacks?
d) How are costs that are accrued to repair damage due to motor vehicle accidents recovered?

SNC response:

a) Costs that are borne by SNC under the System Access category which are not recoverable by the customer are pole replacements or maintenance work related to Joint Use make ready attachments where the assets are at the end of life. In addition, relocations are recoverable at 50% of labour and trucking due to the “Public Service Works on Highways Act”. Finally, new connections receive a new basic service credit amount that is applied to all new residential and commercial customers as detailed in SNC’s Conditions of Service.

b) There does not appear to be a pattern to infrastructure damage due to motor vehicle accidents. They occur infrequently, approximately 10 times per year in different locations and under different conditions.

c) SNC’s design practice in areas where poles may be susceptible to damage from motor vehicle accidents is to request that the road reconstruction include guard rails. When replacing poles SNC follows the setbacks provided by the municipality when assets are located in municipally owned Right of Ways but will review for a more favorable option if the easement or Right of Way has that option. When replacing poles, SNC follows the setbacks provided by the municipality when assets are located in municipally owned Right of Ways but will review for a more favorable option if the easement or Right of Way has that option.

d) SNC is notified by first responders of motor vehicle accidents involving SNC infrastructure. When arriving on scene, SNC staff receive an incident number for a police report that details both the liable party and their applicable insurance information. Costs to repair damages as a result of motor vehicle accidents are recovered by billing the party at fault. The invoices for damages are sent directly to the liable party and if not collected, these invoices are sent to the liable party’s insurance company for collection.

2-STAFF-33

Rate Base

Ref 1: Exhibit 2, Attachment 2, Section 5.3.1.3 Process, page 52, .PDF page 150

Preamble:

Regarding asset management assessment, Synergy North provides Table 5.3-2 Prioritization Criteria.

Question(s):

a) Please explain the rationale for the different weighting assigned to each criteria.
b) Please explain why System Reliability and Asset Performance receive such low weightings when the customer feedback indicates that customers want to maintain low rates and the current level of reliability?

SNC response:

a) Each objective is assigned its own weight, using an analytical hierarchy process based on its relative importance in achieving SNC's objectives. The different weighting reflects the importance to SNC and aligns its criteria with its Corporate and AM objectives. The weighting process is explained further in METSCO's Prioritization Process Report in Section 2.2.
b) SNC has 'Customer Preference' as a criterion that accounts for affordability and reliability in the feedback customers have provided. The criteria are directly linked to the asset management objectives SNC outlined in Section 5.3.1.1 of its DSP. These objectives/criteria are listed in order of importance and are used to inform the project selection and prioritization process. This is why System Reliability and Asset Performance are weighted lower compared to other criteria. It should be noted that inherently, all criteria contribute towards maintaining low rates and sustaining reliability levels.

2-STAFF-34

Rate Base

Ref 1: Exhibit 2, Attachment 2, Section 5.3.1.4 Data, page 56, PDF page 154

Preamble:

Regarding financial metrics, Synergy North states:

"SNC utilizes financial metrics on a per unit basis for its major asset categories based on actual historical replacement to estimate future capital costs for projects of similar size and scope. These metrics are updated annually to ensure that the estimating process continues to be effective and is based on the best available data each year."

Question(s):

a) For each of the major asset categories, please provide the actual historical replacement costs for the past 10 years.

<u>SNC response:</u>

a) Please see Table 2-7 below, which are the financial metrics on a per unit basis for its major asset categories that Synergy North collects and was referring to in the above statement from Exhibit 2, Attachment 2, Section 5.3.1.4 Data, page 56, .PDF page 154.

TABLE 2-7: ACTUAL HISTORICAL REPLACEMENT COSTS

Financial Metric	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Cost per Pole Set	$ 4,701	$ 4,030	$ 5,078	$ 4,805	$ 3,522	$ 6,334	$ 5,354	$ 5,187	$ 5,199	$ 6,651
Costs per Pole Frame/String	$ 5,636	$ 5,366	$ 6,729	$ 6,341	$ 7,882	$ 8,624	$ 6,362	$ 5,145	$ 7,920	$ 9,225
Cost per Pole	$ 10,337	$ 9,396	$ 11,807	$ 11,146	$ 11,405	$ 14,958	$ 11,715	$ 10,331	$ 13,120	$ 15,876
Cost per Transformer	$ 3,615	$ 5,422	$ 6,506	$ 3,498	$ 6,256	$ 6,778	$ 4,582	$ 6,922	$ 3,158	$ 4,784

Labour Metric	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Hours per Pole Set	27.0	26.0	24.0	23.0	22.9	22.9	22.9	22.4	21.1	20.9
Hours per Pole Frame/String	48.0	42.0	41.5	40.0	40.4	40.6	39.2	33.5	32.6	31.8
Hours per Pole	75.0	71.0	78.0	68.5	67.5	83.0	57.0	48.0	53.0	55.0
Hours per Transformer	13.1	7.0	5.8	11.1	1.8	5.5	15.3	4.1	3.6	11.8

<u>Comments</u>

The periods spanning from 2013 to 2017 consisted of projects primarily located in residential neighbourhoods. 2018, and 2022 consisted of projects located in commercial heavy areas.

In the financial metrics, "Cost per pole" includes the total costs to the Corporation on average in that year to install one pole in a system renewal project. This includes all labor, material, subcontractor cost, overheads, etc. Similarly, this follows for the "Cost per transformer" metric where it includes the total costs to the Corporation on average in that year to install one transformer in a system renewal project.

In the labour metrics, "Hours per pole" includes the total hours spent to completely renew one pole, this includes transportation of material to site, installation in the ground, attaching all fixtures and wires to the pole and completing the transfer of any services. Similarly, this follows for the "Hours per Transformer," where the hours include the transportation, installation, and completion of connections to fully energized for a transformer.

The historical replacement costs of poles and transformers do not reflect what future years project costs will be as:

SNC has experienced significant increases in material pricing, as stated on page 48 of Exhibit 1, where the cost for Pad mount transformers has increased by an average of 75% on the most common units ordered by SNC from 2022 to 2023 due to the significant cost increase of core steel. Additionally, the price of wood poles has increased by 17% from 2022 to 2023.

The 4kV conversion program has moved from the rural predominantly residential outskirts of the city to the downtown urban core areas of the city in 2023 and forecasted years. The work in downtown urban areas will have a large impact on commercial customers and due to the nature of their underground services and operating hours, will have a higher complexity and require that SNC perform the work outside of normal operating hours, resulting in higher costs.

The type of work in the forecast period does not reflect the type of work done historically. The completion of the 4kV conversions will be in the densest urban areas of Thunder Bay in a mix of street front, easement, and underground commercial areas. These commercial areas are typically underground serviced and less likely to be able to be rebuilt in a like-for-like manner. Due to this they require a greater amount of coordination with commercial parties as well as the municipality. The 4kV conversion of underground areas are more complex to relocate as the legacy installations are often in high-risk areas, where real estate is at a premium. Locations such as parking lots require mechanical protection such as concrete bollards to be installed, and locations next to metallic surfaces require relocation to remove the risks of electrical shock to the public. In addition, the remediation efforts due to pole setting and trenching for services in these areas are also more costly as they require replacement of sidewalks and decorative patio stones.

2-Staff-35

Rate Base

Ref 1: Exhibit 2, Attachment 2, Section 5.3.2.1.5 Asset Condition and Demographics, page 64, .PDF page 162

Ref 2: Exhibit 2, Attachment 2–A, Section 5.3.1 Planning Process, page 42, .PDF page 140

Preamble:

Please refer to Table 5.3-7 Major Distribution Assets on page 64 of the Distribution System Plan.

Regarding Asset Removal Data, Synergy North states on page 42:

"Also in 2019, SNC began to collect data on the driver for replacement for its major asset categories including but not limited to, poles, switches, cables, and transformers. The intent of the results was again to inform the ACA with objective information regarding the age at which assets fail. The data collected can be compared against the statistical models developed in the ACA to improve the quality of the analysis. This was identified as an area for improvement following the ACA in 2015. SNC will continue to collect this information and use it to inform statistical rates-of-failure models during this investment cycle."

Question(s):

a) Please update table 5.3.7 to show additional columns for Average Replacement Rate (e.g., over the past 1, 3 or 5 years as appropriate), Implied Asset Service Life (= Quantity / Average Replacement Rate), SNC's current estimate of Age at Which Assets Fail, and TUL replacement costs for the past 10 years.
b) Please confirm that the estimates for the ages at which assets fail only includes assets that actually failed in service and does not include assets that were removed from service due to deteriorated condition.

- If not confirmed, please reconcile with the statement that SNC is seeking to "inform the ACA with objective information regarding the age at which assets fail"

SNC response:

a) Please see Table 2-8 below.

TABLE 2-8: MAJOR DISTRIBUTION ASSETS

Asset Description	Quantity (units[1])	Average Replacement Rate (2019-Q2 2023)	Implied Asset Service Life	Estimated Age at Which Assets Fail	TUL Replacement Costs
Power Transformers	20	(2)	(2)	(2)	(2)
Circuit Breakers	58	(2)	(2)	(2)	(2)
Wood Poles	22362	95	235	54	$12,009
Pad Mount Transformers	2490	17	146	42	$10,216
Pole Mounted Transformers	4900	15	327	48	$5,152
Vault Transformers	280	(1)	(1)	(1)	(1)
Overhead Switches	990	9	110	35	$10,144
Underground Switches	88	(1)	(1)	(1)	(1)
Reclosers	65	(1)	(1)	(1)	(1)
Metering	57,074	(3)	(3)	(3)	(3)
Overhead Primary Conductor	998 cct-km	(1)	(1)	(1)	(1)
Overhead Secondary Cable	1169 cct-km	(1)	(1)	(1)	(1)
Underground Primary Cable	277 cct-km	4.4	63	52	$158/m
Underground Secondary Cable	519 cct-km	0.1	5190	55	$137/m

(1) - Replacement data unavailable - SNC has not replaced these assets in the time period requested

(2) - In service failures have occurred - but these assets are repaired rather than replaced

(3) - These assets are not tracked via the asset removal process

b) Confirmed.

2-STAFF-36

Rate Base

Ref 1: Exhibit 2, Attachment 2, Appendix I: ACA Update Summary, Page 6, .PDF Page 609

2022 Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	
Station Transformers	All	20	20	75%	5%	5%	35%	15%	40%	53
	4 kV	11	11	63%	10%	10%	50%	10%	20%	63
	12 kV	9	9	89%	0%	0%	10%	20%	70%	40
Breakers	Breakers	58	58	70%	9%	0%	37%	26%	28%	62
Wood Poles	All	22362	22362	83%	0%	7%	17%	23%	52%	29
	4 kV	1381	1381	74%	0%	9%	33%	28%	30%	41
	25 and 12kV	20981	20981	82%	0%	7%	16%	23%	54%	25

Question(s):

a) What is the target health index for each of the identified asset classes in the above table?

b) Please correlate improvements in system reliability to improvements in health indices for wood poles, OH and UG Switches, distribution transformers, station transformers, and circuit breakers.

SNC response:

a) The target for each asset is as follows:

- 4kV Station Transformers – these assets are targeted for decommissioning as part of the 4kV Conversion program, and as such have no specific health target.
- 12kV Station Transformers – The average health index target is between 80% and 85%.
- Breakers – these assets are targeted for decommissioning as part of the 4kV Conversion Program and as such, have no specific health target.
- 4kV Wood Poles - these assets are targeted for replacement to operate at 25kV as part of the 4kV Conversion Program, and as such have no specific health target.
- 25kV & 12kV Wood Poles - The average health index target is between 80% and 85%.

b) SNC is unable to quantify the reliability improvement in terms of SAIDI and SAIFI delivered specifically by System Renewal investments. It's important to note that the correlation between system renewal activities and electricity reliability statistics is not absolute as reliability can be influenced by factors such as weather events, changes in demand, and external factors beyond the utility's control. Additionally, SNC also undertook OM&A initiatives that would have had an impact on improvements in reliability such as the Vegetation Management program.

2-Staff-37

Rate Base

Ref 1: Exhibit 2, Attachment 2, Appendix I: ACA Update Summary, page 5, .PDF page 608

Preamble:

According to Section 2 Data Availability and Data Gap Comparison 2015 and 2022, average DAI for wood poles in 2015 was 100% and 77% in 2022.

Question(s):

a) Please explain why DAI went down between 2015 and 2022 for Wood Poles
    - In 2015, was the DAI based solely on age? If not, why does collecting condition data reduce the DAI?

SNC response:

a) DAI was not solely age based for wood poles in 2015, as other visual inspection data had been incorporated into the analysis at that time. The ACA conducted by Kinectrics included an assessment of where data gaps existed in the data. SNC has worked diligently to address the largest and most significant data gaps identified in the ACA. In the case of wood poles, the major data gap identified was the remaining strength at the groundline. By collecting this quantitative data and incorporating it into the ACA, it has the effect of immediately decreasing the DAI for those assets for which the data has yet to be collected (this is due to a small portion of the population now having an extra condition parameter relative to the remaining population).

For example, when SNC collected strength data for 1200 poles, these poles now have 100% data availability. The remaining population (approximately 22000) has gone from previously having 100% data availability to some fraction less because there is no strength data available.

SNC has taken a measured approach with regard to the difficulty and cost associated with collecting this data against the benefits associated with increased confidence in the assessment.

2-STAFF-38

Rate Base

Ref 1: Exhibit 2, Attachment 2, Appendix K: METSCO PROGRAM PRIORITIZATION REPORT, page 8, .PDF page 695

Preamble:

Synergy North's Asset Management Objectives, Description and Weighting is provided in Table 1. Health and Safety has a weight of 41.1% and Environmental Impact has a weighting of 22.9%.

Question(s):

a) Please explain why Health and Safety and Environmental Impacts have such high weightings.

SNC response:

a) As outlined in METSCO's report in Section 2.2., each Asset Management Objective is assigned its own weight, using an analytical hierarchy process based on its relative importance in achieving SNC's objectives. Like any utility, health and safety and environmental impacts are top priorities for ensuring the safe and efficient delivery of services to its customers, keeping the public safe, and minimizing any environmental impacts. For most organizations, these two criteria are non-negotiable and should always be prioritized first. This is evident in a recent application[1] filed by Elexicon Energy Inc. where, as part of their project prioritization process, they weight "Worker/Public Safety" and "Workforce Health and Productivity" a combined 49.7%, and Environmental Impact at 11.4%, totalling 61.1%.

[1] Appendix I of the DSP - EB-2021-0015 – Elexicon Engery Inc., 2022 IRM Rate Application

These figures are in line with SNC's total combined weighting of Health and Safety and Environmental Impacts of 64%.

2-Staff-39

Rate Base

Ref 1: Exhibit 2, Table 5.2-6 Major Event Details, page 65, .PDF page 130

Preamble:

Synergy North states that there was one major event day in the historic period, where in December of 2017 a windstorm caused resonant conductor galloping.

Question(s):

a) What steps has Synergy North taken to prevent resonant conductor galloping from recurring within its distribution system?

SNC response:

a) The section of line where the galloping occurred has since been rebuilt using shorter span lengths and greater spacing between the phases. This should have the effect of reducing the instance of resonant galloping from reoccurring.

2-Staff-40

Ref 1: SNC_2024_Chapter2_Appendices_20230816, Tabs A App. _FA Cont SNC 2022 & SNC 2021

Ref 2: SNC 2024 COS Application, Exhibit 1, Attachment 1-H, SNC Financial Statement 2022, page 19

Preamble:

OEB staff noted the additions and disposals recorded in Appendix 2-BA different from what was reported in Synergy North's 2022 Audited Financial Statements (AFSs). Table 1 below presents a summary of the variances.

Table 1: Summary of Variances between App 2-BA and 2022 AFS

Balances as of December 31, 2022	Reference 1 Total PP&E excluding Deferred Revenue	Reference 2	Variances
Cost – Additions	$17,187,570	$17,195,995	$8,425
Cost – Disposals	$(1,618,013)	$(1,634,465)	$(16,452)
Accumulated Depreciation – Additions	$(6,306,049)	$(6,474,626)	$(168,577)

Balances as of December 31, 2021	Reference 1 Total PP&E excluding Deferred Revenue	Reference 2	Variances
Cost – Additions	$15,103,531	$15,211,634	$108,103
Cost – Disposals	$(1,884,379)	$(1,976,582)	$(92,203)
Accumulated Depreciation – Additions	$(5,859,655)	$(6,027,134)	$(167,749)

Question(s):

a) Please provide an explanation/ reconciliation for the discrepancies noted above and update the applicable schedules as necessary.

SNC Response:

a) Please see Table 2-9 below.

TABLE 2-9: RECONCILIATION OF 2BA TO AUDITED FINANCIAL STATEMENTS

Balances as of December 31, 2022	Reference 1 Total PP&E excluding Deferred Revenue	Reference 2	Variances	Explanations
Cost – Additions	$17,187,570	$17,195,995	$8,425	This is made up of adjustment of ($8,027) to the Station Decomissioning ARO (not-included in rate base), as well as removing $16,452 of line transformers brought back into inventory as these are not new capital additions.
Cost – Disposals	-$1,618,013	-$1,634,465	-$16,452	$16,452 of line transformers brought back into inventory.
Accumulated Depreciation – Additions	-$6,306,049	-$6,474,626	-$168,577	This is made up amortization of non-wires assets removed from 2-BA, including solar asset amortization, amortization of sentinel lights, ARO amortization, and amortization of SNC's power house (non-wires asset). Further, amortization of wholesale gate meters is not included in the figure in Reference 2.

Balances as of December 31, 2021	Reference 1 Total PP&E excluding Deferred Revenue	Reference 2	Variances	Explanations
Cost – Additions	$15,103,531	$15,211,634	$108,103	This is made up of adjustment of $15,899 to the Station Decomissioning ARO (not-included in rate base), as well as removing $92,203 of line transformers brought back into inventory as these are not new capital additions.
Cost – Disposals	-$1,884,379	-$1,976,582	-$92,203	$92,203 of line transformers brought back into inventory.
Accumulated Depreciation – Additions	-$5,859,655	-$6,027,134	-$167,749	This is made up amortization of non-wires assets removed from 2-BA, including solar asset amortization, amortization of sentinel lights, ARO amortization, and amortization of SNC's power house (non-wires asset). Further, amortization of wholesale gate meters is not included in the figure in Reference 2.

SCHOOL ENERGY COALITION

2-SEC-9

[Ex.2, Attach 2-A, p.34]

Please provide the following figures in tabular format and provide a breakdown by service territory.

a) 5.2-14
b) 5.2-15
c) 5.2-16

SNC response:

a) Please see Table 2-10 and Table 2-11 below

TABLE 2-10: KENORA OUTAGES BY CAUSE CODE

Kenora – Outage Events by Cause Code						
	2017	2018	2019	2020	2021	2022
0 - Unknown/Other	0	0	5	3	5	8
1 - Scheduled Outage	31	41	46	16	30	113
2 - Loss of Supply	1	2	20	6	0	24
3 - Tree Contacts	7	3	3	4	5	2
4 - Lightning	0	0	6	0	0	0
5 - Defective Equipment	11	11	13	6	5	4
6 - Adverse Weather	1	1	0	0	0	0
7 - Adverse Environment	3	0	0	0	0	0
8 - Human Element	0	0	0	0	2	0
9 - Foreign Interference	11	6	2	7	11	7
10 – Major Event	0	0	0	0	0	0

TABLE 2-11: THUNDER BAY – OUTAGE EVENTS BY CAUSE CODE

Thunder Bay – Outage Events by Cause Code						
	2017	2018	2019	2020	2021	2022
0 - Unknown/Other	47	37	51	39	52	52
1 - Scheduled Outage	223	174	200	225	293	214
2 - Loss of Supply	24	12	5	12	0	6
3 - Tree Contacts	87	114	91	43	65	90
4 - Lightning	12	19	6	24	27	19
5 - Defective Equipment	145	130	143	154	157	166
6 - Adverse Weather	3	16	4	1	3	1
7 - Adverse Environment	1	4	1	2	4	0
8 - Human Element	4	2	4	3	8	4
9 - Foreign Interference	172	159	180	191	190	167
10 – Major Event	2	0	0	0	0	0

b) Please see Table 2-12 below.

TABLE 2-12: KENORA AND THUNDER BAY - CUSTOMER INTERRUPTIONS BY CAUSE CODE

Kenora - Customer Interruptions by Cause Code						
	2017	2018	2019	2020	2021	2022
0 - Unknown/Other	0	0	40	20	56	643
1 - Scheduled Outage	5,894	480	673	139	312	1,102
2 - Loss of Supply	5,576	11,171	19,591	5,148	0	20,592
3 - Tree Contacts	1,560	4	123	98	321	16
4 - Lightning	0	0	5,192	0	0	0
5 - Defective Equipment	414	90	3,299	253	170	30
6 - Adverse Weather	1	8	0	0	0	0
7 - Adverse Environment	2,527	0	0	0	0	0
8 - Human Element	0	0	0	0	470	0
9 - Foreign Interference	65	68	17	313	3,077	483
10 - Major Event	0	0	0	0	0	0
Thunder Bay - Customer Interruptions by Cause Code						
	2017	2018	2019	2020	2021	2022
0 - Unknown/Other	23,625	20,220	26,939	14,533	24,475	41,815
1 - Scheduled Outage	4,151	4,960	5,318	6,259	6,167	6,783
2 - Loss of Supply	31,511	27,577	11,382	23,885	0	10,691
3 - Tree Contacts	29,609	37,177	13,898	11,647	11,173	16,568
4 - Lightning	2,717	10,422	325	5,353	3,684	9,179
5 - Defective Equipment	40,430	25,609	34,096	22,336	22,940	37,437
6 - Adverse Weather	50,854	8,595	2,264	74	105	25
7 - Adverse Environment	4,164	60	8	2,063	2,225	0
8 - Human Element	1,306	2,056	972	328	1,173	3,815
9 - Foreign Interference	48,167	37,337	33,827	41,297	34,839	11,117
10 - Major Event	50,180	0	0	0	0	0

c) Please see Table 2-13 below

TABLE 2-13: KENORA AND THUNDER BAY - CUSTOMER HOURS OF INTERRUPTION BY CAUSE CODE

Kenora - Customer Hours of Interruption by Cause Code						
	2017	2018	2019	2020	2021	2022
0 - Unknown/Other	0	0	62	32	86	880
1 - Scheduled Outage	4,353	978	600	216	794	891
2 - Loss of Supply	3,996	20,556	26,482	1,544	0	1,908
3 - Tree Contacts	2,566	6	343	103	2,346	16
4 - Lightning	0	0	10,603	0	0	0
5 - Defective Equipment	5,740	128	2,200	555	365	73
6 - Adverse Weather	1	13	0	0	0	0
7 - Adverse Environment	13,833	0	0	0	0	0
8 - Human Element	0	0	0	0	1,547	0
9 - Foreign Interference	80	67	19	378	4,871	971
10- Major Event	0	0	0	0	0	0
Thunder Bay - Customer Hours of Interruption by Cause Code						
	2017	2018	2019	2020	2021	2022
0 - Unknown/Other	4,829	3,365	9,813	1,435	2,914	4,267
1 - Scheduled Outage	6,192	8,460	5,202	6,849	14,304	16,648
2 - Loss of Supply	11,682	5,191	3,699	12,609	0	42
3 - Tree Contacts	31,616	57,468	17,905	9,375	13,769	15,673
4 - Lightning	958	1,562	396	2,483	1,911	8,567
5 - Defective Equipment	16,520	15,667	13,172	9,735	19,065	23,943
6 - Adverse Weather	78,906	12,239	567	87	138	29
7 - Adverse Environment	277	100	1	469	585	0
8 - Human Element	419	285	107	293	327	140
9 - Foreign Interference	21,870	19,278	18,437	10,435	9,666	7,416
10- Major Event	78,958	0	0	0	0	0

2-SEC-10

[Ex.2, Attach 2-A, p.65]

Please provide a version of Figure 5.3.9 in tabular format that shows for each asset category, the number of assets, and the percentage of those assets in each asset condition category. Please provide the information in Excel format.

SNC response:

See Excel spreadsheet SNC_2-SEC-10 – DSP Tabular Form of Health Index_20231110.

2-SEC-11

[Ex.2, Attach 2-A, p.65]

The Applicant states that “Health Index (HI) is a composite quantitative measure of an asset’s condition based on available condition data (testing, inspections, utilization, expert opinion, age, etc.).”

a) Please explain specifically how age is used to determine the Health Index.
b) Please provide a revised version of the asset Health Index information for each asset that removes age as a condition variable.

SNC response:

a) Age is used in the Health Index as follows.

Assume that the asset failure rate increases exponentially with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failures per unit time)

t = time

α, β = constant parameters that control the rise of the curve

The corresponding survival function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survival function

P_f = cumulative probability of failure

Assuming that for a particular asset (wood pole) at ages 60 and 75 years, the probability of failure (P_f) is 20% and 95%, respectively.

This results in the survival curve shown below:

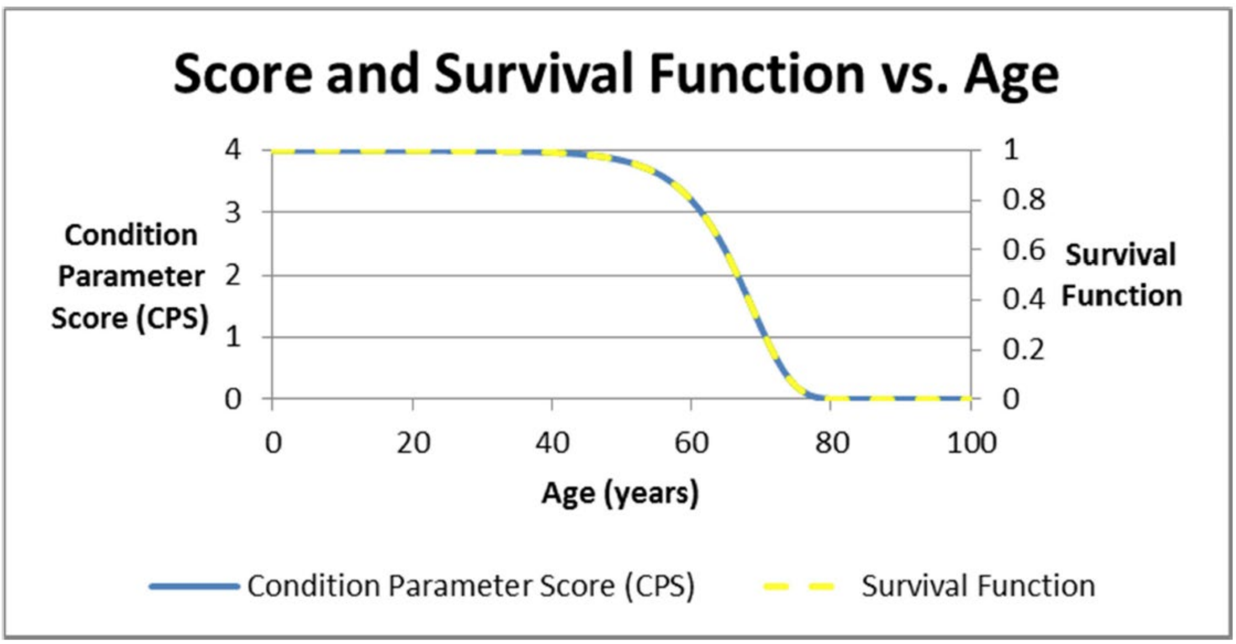


Figure: Asset Survival vs Condition Parameter Score

It follows that assets that are new (age = 0) have the maximum condition parameter score of 4 (4 x 1 Survival Function value) and that as assets age, the condition score follows the curve to eventually reach 0.

The age is a weighted condition parameter and is used in conjunction with other condition parameters to determine the overall health of individual assets. The table below details the condition parameters for wood poles and their relative weighting; this table can also be found in Exhibit 2, Appendix H Material Investment Report – System Renewal – Line Safety Reports.

TABLE 2-14: WOOD POLE CONDITION PARAMETERS

Pole Remaining Strength	38%
Overall Condition	19%
Ground Line Rot	6%
Mechanical Damage	6%
Age	5%
Shell Rot	3%
Split	3%
Woodpecker Hole	3%
Insect Damage	3%
Leaning	3%
Feathering	3%
Crossarm	3%

b) SNC has carefully reviewed this request to exclude age as a condition variable from the Health Index calculation and has provided the table below as a response to this question. However, in most cases, this has caused either a significant decrease in the sample size (used to calculate the health index) or complete corruption of the calculation (as is the case in Pole Mounted transformers and Vault transformers).

While this adjustment may seem like a straightforward modification, it is important to consider the broader implications and potential challenges associated with removing age as a condition variable in health index information.

Age is a fundamental parameter that provides context to an asset's condition. It serves as a historical marker, offering insights into how an asset has aged over time. Removing age as a condition variable could potentially compromise the integrity of our data and the accuracy of the Health Index.

Age is a critical factor when assessing the degradation and wear-and-tear of an asset. It allows SNC to track long-term trends in asset performance and condition, which is crucial for making informed decisions about maintenance, repair, and replacement strategies.

Age is a key determinant in forecasting the future condition and performance of an asset. By removing age as a variable, we might lose the ability to proactively plan for the maintenance, refurbishment, or replacement of assets before they reach a critical condition.

TABLE 2-15: HEALTH INDEX WITH AGE REMOVED

Asset Category		Population	Sample Size	Average Health Index
All TX Transformers	All	20	20	75%
	4 kV	11	11	63%
	12 kV	9	9	89%
Breakers	Breakers	58	58	70%
Wood Poles	All	22362	17797	83%
Pad Mounted Transformers		2490	1139	72%
Pole Mounted Transformers		4900	-	-
Vault Transformers		280	-	-
OH Switches	All	990	209	94%
Underground Switches	25kV Underground Load Break Switches	88	1	100%
Underground Cables	All	445	1	55%

The methodology to generate the Health Index in the ACA was created by Kinetrics during Thunder Bay's last cost of service application in 2016 using industry standard probabilistic modelling that includes age and other variables to increase the probability of a correct prediction of asset failure.

Once age is removed from the calculations, SNC gives no assurances on the predictive value of the model as we are unable to test the model and such a model is outside the scope of the methodology considered by Kinetrics. There is no predictive value in forecasting the timing of asset replacements if age is removed from the Health Index. Further, there are a number of statistical studies and articles that discuss the positive statistical relationship between distribution asset age and the rate of failure. Some of these studies include the following P&E Magazine Articles:

- Power system equipment aging, Wenyuan Li; E. Vaahedi;P. Choudhury, IEEE Power and Energy Magazine, Year: 2006 | Volume: 4, Issue: 3 | Magazine Article | Publisher: IEEE, Cited by: Papers (42).
- The economics of aging infrastructure, R.E. Brown; H.L. Willis, IEEE Power and Energy Magazine, Year: 2006 | Volume: 4, Issue: 3 | Magazine Article | Publisher: IEEE, Cited by: Papers (15).
- Aging, maintenance, and reliability – approaches to preserving equipment health and extending equipment life, J. Endrenyi; G.J. Anders, IEEE Power and Energy Magazine, Year: 2006 | Volume: 4, Issue: 3 | Magazine Article | Publisher: IEEE, Cited by: Papers (54)
- Life extension and condition assessment: techniques for an aging utility infrastructure, N. Dominelli; A. Rao;P. Kundur, IEEE Power and Energy Magazine, Year: 2006 | Volume: 4, Issue: 3 | Magazine Article | Publisher: IEEE, Cited by: Papers (12)
- Time management for assets: chronological strategies for power system asset management, M. Shahidehpour; R. Ferrero, IEEE Power and Energy Magazine, Year: 2005 | Volume: 3, Issue: 3 | Magazine Article | Publisher: IEEE, Cited by: Papers (39)

2-SEC-12

[Ex.2, Attach 2-A, p.65]

For each asset category, please provide the number of assets replaced each year, between 2017 and 2022, and forecast to be replaced between 2023 and 2028.

SNC response:

For the years 2017 through 2028, see Table 2-16 below.

TABLE 2-16: ASSETS ACTIONED 2017-2028

	Station Transformers		Breakers	Wood Poles	Distribution Transformers			OH Switches							Underground Switches	Underground Cables	
	4 kV	12 kV	Breakers	All Wood Poles	Pad Mounted Transformers	Pole Mounted Transformers	Vault Transformers	4kV In-Line	4kV Manual Air Break	12 and 25kV In-Line	12 and 25kV Manual Air Break	115kV Air Break	25kV Motorized Load Break	Reclosers	25kV Underground Load Break Switches	4kV	12 and 25kV
2017 Assets Actioned	1	0	5	432	59	116	6	18	0	12	14	0	0	0	0	0.6	1.8
2018 Assets Actioned	1	0	5	432	33	158	0	10	2	17	3	0	2	7	0	0.9	2.8
2019 Assets Actioned	1	0	9	463	39	116	0	0	0	17	3	0	0	1	0	1.4	3.5
2020 Assets Actioned	0	0	0	535	14	112	3	12	0	7	4	0	0	0	0	0.5	0.4
2021 Assets Actioned	0	0	0	465	61	154	3	16	1	7	1	0	0	1	0	1.7	4.9
2022 Assets Actioned	0	0	0	509	21	91	3	12	1	13	3	0	0	3	0	0.9	2.1
2023 Proposed Assets to be Actioned	1	0	5	341	34	95	0	28	0	4	1	0	0	2	0	0.7	2.0
2024 Proposed Assets to be Actioned	1	0	4	440	67	83	5	15	0	11	2	0	0	3	0	2.3	3.5
2025 Proposed Assets to be Actioned	1	0	0	335	80	141	23	1	0	1	8	0	0	3	0	1	5
2026 Proposed Assets to be Actioned	0	0	0	336	80	141	23	1	0	1	8	0	0	3	0	1	5
2027 Proposed Assets to be Actioned	0	0	0	336	71	141	23	1	0	2	8	0	0	3	0	1	5
2028 Proposed Assets to be Actioned	3	0	0	336	40	46	7	1	0	2	8	0	0	3	0	1	5

2-SEC-13

[Ex.2, Attach 2-A, p.126] With respect to the Applicant's project prioritization:

a) Please provide a table that shows project prioritization for all 2024 capital projects (regardless of individual cost), the project costs, prioritization score, and the score for each prioritization criteria.

b) Please confirm that the prioritization process prioritizes the projects that the Applicant already has determined that it will undertake in a given year.

c) The Applicant appears to aggregate many individual projects within a given program. Does the Applicant provide a prioritization score to each individual project/asset replacement, or only at the program level? If not, please explain why not.

SNC response:

a) See Table 2-17 below.

TABLE 2-17: PRIORITIZING MATRIX WITH SCORING FOR TEST YEAR PROGRAMS OVER MATERIALITY

Programs	Health and Safety	Environmental Impact	Regulatory/Legal Compliance	Customer Preference	Asset Performance	Operational Efficiency	System Reliability	Score	Category	2024 Gross Expenditures ($'000)
Weight	41.1%	22.9%	12.3%	8.4%	6.3%	4.7%	4.2%			
Lines Safety Reports	15	15	10	15	15	5	5	67.5%	System Renewal	859
4kV Overhead Conversions	10	20	5	15	20	20	15	67.0%	System Renewal	7219
Overhead Renewal	10	15	0	20	15	5	5	53.1%	System Renewal	1557
Transformer/Switch/Switchgear Replacements	10	10	5	15	15	5	5	48.4%	System Renewal	932
Small Pole Replacements	10	10	0	15	10	5	5	43.7%	System Renewal	767
Underground Renewal	5	15	0	15	15	10	5	41.9%	System Renewal	646
Fleet/Rolling Stock	10	10	5	5	10	5	0	41.5%	General Plant	600
Information Systems	10	0	5	0	20	5	0	31.1%	General Plant	305
Grid Modernization	0	0	0	10	0	0	20	8.5%	System Service	323

b) Yes, SNC confirms that the output of the prioritization process assists SNC in determining which projects it will undertake in a given year and when necessary, also assists in reprioritizing between years.

c) The prioritization score has only been applied to the projects listed in Table 5.4-10 of the DSP, except for System Access projects. System Access projects are mandatory, non-discretionary projects. These mandatory capital expenditures are automatically promoted to the appropriate years' investment plan rather than receiving a Priority Score. Where a project may be classified as a program, typically, these projects are all the same type of project, with the same drivers and therefore a similar impact. By grouping these similar smaller projects under one program, the prioritization score would be the same as if they were assessed individually. For example, for the 4kV Conversion Program, there are multiple 4kV conversion projects with the same aim of addressing failure risk due to end-of-life assets, reducing system losses, accommodation for grid modernization technologies, etc.

2-SEC-14

[Ex.2, Attach 2-A, Appendix D, p.20]

Is the Applicant undertaking in 2023 and proposing to undertake in 2024 the planned investments included in Figure 11?

SNC response:

TABLE 2-18: FINO INVESTMENTS 2023 AND 2024

FINO Plan- Capital	*2023*	*2024*
Recloser (Reliability)	$272,000	$277,440
BTM Batteries (Planned Outages)	$ -	$ 45,000
SNC Capacity - System Upgrades due to EV	$ -	$ -
SNC Capacity - SCADA Upgrades	$ 20,000	$ 20,400
Total Capital Expenditure	$292,000	$342,840
FINO Plan - OM&A	*2023*	*2024*
SNC Capacity	$ 35,000	$ 25,000
EV Support and Services	$ 10,000	$ 25,000
FINO Software Upgrades	$ -	$ -
Total OM&A Expenditure	$ 45,000	$ 50,000

In 2023, SNC will complete the SCADA upgrades. Two out of the three reclosers budgeted will be completed and one has been deferred as a result of cost overruns in General Plant in 2023, resulting in a $92k deferral. The OM&A budget of $45k will be spent.

In 2024, SNC is planning to undertake all the 2024 planned investments. The reclosers and the SCADA upgrades are included under the System Service budget, and the Batteries have been included in the General Plant budget. Obtaining consulting services for predictions of electrification and options for KMTS as well as upgrading SNC's portal and website, are included in OM&A Budgets.

2-SEC-15

[Ex.2, Appendix 2-AA]

Please provide a revised version of Appendix 2-AA 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.

SNC response:

Please refer to the revised SNC_2024_Chapter2_Appendices_20231110 with the additional columns added to Appendix 2-AA to show year-to-date actuals (up to September 30) for 2021, 2022, and 2023.

2-SEC-16

[Ex.2, Appendix 2-AB]

Please provide a copy of Appendix 2-AB on an in-service additions basis.

SNC response:

Please refer to a revised Appendix 2-AB excel file based on in-service additions, SNC_2-SEC-16 – 2-AB (in-service basis)_20231110. Refer 2-AMPCO-5 for assumptions made with regards to the calculation of in-service additions.

2-SEC-17

[Ex.2, Appendix 2-AB]

Please explain the basis for the 'Plan' amount each year between 2017 and 2023.

SNC response:

The plan amounts in 2017 through to 2021 found in Appendix 2-AB are based on the DSP forecast submitted by TBHEDI in its last cost of service, less a total of 1 million[2] across all of capital programs in 2017 for reductions related to the Cost of Service Decision. In addition, $910K from the approved Kenora application was added in the years 2017 through to 2023. Kenora's approved capital plan amounts include an annual inflationary increase. Beyond the DSP time frame of 2021, budget figures were used for 2022 and 2023.

2-SEC-18

[Ex.2, Appendix 2-AB]

Please expand Appendix 2-AA to show forecast capital expenditures between 2025 and 2028.

[2] from Decision and Order by the OEB - application EB-2012-0167.

SNC response:

Please refer to a revised Excel file SNC_2-SEC-18-2AA Forecast_20231110 showing forecast capital expenditures between 2025 and 2028.

ASSOCIATION OF MAJOR POWER PRODUCERS (AMPCO)

2-AMPCO-5

Ref: Appendix 2-AA

Please provide Appendix 2-AA on the basis of in-service additions.

SNC response:

An updated Appendix 2-AA, based on in-service additions, is provided in a live Excel file entitled , SNC_2-AMPCO-5 – 2-AA_ (in-service basis)_ 20231110.

Please note that this information is based on a review of all larger capital projects that were not in-service at year-end, and Appendix 2-AA capital expenditures have been adjusted accordingly. Smaller projects that were not in-service at year-end were not adjusted as the difference between capital expenditures and in-service additions was below materiality. The last line on the Updated Appendix 2-AA entitled "Difference", is the remaining aggregate difference between capital expenditures and in-service additions.

2-AMPCO-6

Ref: Ex. 2 p. 81

Please complete the following table:

Costs	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
Labour								
Material								
Third Party								

SNC response:

Please see Table 2-19 below.

TABLE 2-19: CAPITALIZED COSTS

Costs	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast
Labour	2,166,238	2,159,167	2,605,083	2,134,382	2,886,114	2,555,040	2,983,172	3,194,578
Material	3,348,142	2,965,710	3,046,130	2,782,240	3,306,646	3,428,916	3,194,864	3,518,394
Third Party	3,287,799	2,950,268	3,672,818	3,017,357	4,212,366	5,083,017	4,705,757	3,594,988

2-AMPCO-7

Ref: Ex 2. P. 85 Table 2-31

a) With respect to Overhead Expenses, please define Downtime.

b) Please explain the increase in Downtime in 2024 compared to 2022 Actuals.

SNC response:

a) Downtime is further discussed in Exhibit 2, page 85 under the heading "Indirect Labour Burden". Downtime is comprised of the related payroll costs for the powerline technician group (“PLT”) and includes costs associated with vacation, statutory holidays, sick leave, other leaves of absence, employee training, safety programs and other non-direct work related hours.

b) The majority of the increase in Downtime in 2024 over 2022, relates directly to approved wage increases of 3% for both 2023 and 2024 combined with additional PLTs. The remaining difference relates to the difference between actual and budgeted downtime hours per PLT. SNC budgets 620 annual hours of downtime which equates to what each PLT is entitled to for Vacation, Statutory Holidays and Training and the historical average for sick time and other miscellaneous downtime. 2022 also saw a decrease in training days as a continued result of COVID and the availability of trainers. 2024 includes a return to normal training requirements.

2-AMPCO-8

Ref: Ex 2 Appendix 2-A p. 29

Please complete the following table:

# interruptions	2017	2018	2019	2020	2021	2022
Thunder Bay						
Kenora						

SNC Response:

TABLE 2-20: NUMBER OF INTERRUPTIONS

# interruptions	2017	2018	2019	2020	2021	2022
Thunder Bay	720	667	685	694	799	719
Kenora	65	64	95	42	58	158

2-AMPCO-9

Ref: Ex 2 Appendix 2-A p. 33 Figure 5.2-14

a) Please provide the numerical values for each of the years 2017 to 2022 by cause code.

b) Please provide a further breakdown of Defective Equipment by cause code for each of the years 2017 to 2022.

SNC response:

a) Please see Table 2-21 below.

TABLE 2-21: SNC – OUTAGES BY CAUSE CODE

SNC - Outages by Cause Code						
	2017	**2018**	**2019**	**2020**	**2021**	**2022**
0 - Unknown/Other	47	37	56	42	57	60
1 - Scheduled Outage	254	215	246	241	323	327
2 - Loss of Supply	25	14	25	18	0	30
3 - Tree Contacts	94	117	94	47	70	92
4 - Lightning	12	19	12	24	27	19
5 - Defective Equipment	156	141	156	160	162	170
6 - Adverse Weather	4	17	4	1	3	1
7 - Adverse Environment	4	4	1	2	4	0
8 - Human Element	4	2	4	3	10	4
9 - Foreign Interference	183	165	182	198	201	174
10 – Major Event	2	0	0	0	0	0

b) SNC categorizes events by standard OEB outage categories with Defective Equipment, as shown in the above table.

2-AMPCO-10

Ref: Ex 2 Appendix 2-A p. 34 Figure 5.2-15

a) Please provide the numerical values for each of the years 2017 to 2022 by cause code.

b) Please provide a further breakdown of Defective Equipment by cause code for each of the years 2017 to 2022.

SNC response:

a) Please see Table 2-22 below.

TABLE 2-22: SNC - CUSTOMER INTERRUPTIONS BY CAUSE CODE

SNC - Customer Interruptions by Cause Code						
	2017	**2018**	**2019**	**2020**	**2021**	**2022**
0 - Unknown/Other	23,625	20,220	26,979	14,553	24,531	42,458
1 - Scheduled Outage	10,045	5,440	5,991	6,398	6,479	7,885
2 - Loss of Supply	37,087	38,748	30,973	29,033	0	31,283
3 - Tree Contacts	31,169	37,181	14,021	11,745	11,494	16,584
4 - Lightning	2,717	10,422	5,517	5,353	3,684	9,179
5 - Defective Equipment	40,844	25,699	37,395	22,589	23,110	37,467
6 - Adverse Weather	50,855	8,603	2,264	74	105	25
7 - Adverse Environment	6,691	60	8	2,063	2,225	0
8 - Human Element	1,306	2,056	972	328	1,643	3,815
9 - Foreign Interference	48,232	37,405	33,844	41,610	37,916	11,600
10 - Major Event	50,180	0	0	0	0	0

b) SNC categorizes events by standard OEB outage categories with Defective Equipment shown in the above table.

2-AMPCO-11

Ref: Ex 2 Appendix 2-A p. 34 Figure 5.2-16

a) Please provide the numerical values for each of the years 2017 to 2022 by cause code.

b) Please provide a further breakdown of Defective Equipment by cause code for each of the years 2017 to 2022.

SNC Response:

a) Please see Table 2-23 below.

TABLE 2-23: SNC - CUSTOMER HOURS OF INTERRUPTION BY CAUSE CODE

SNC - Customer Hours of Interruption by Cause Code						
	2017	**2018**	**2019**	**2020**	**2021**	**2022**
0 - Unknown/Other	4,829	3,365	9,874	1,467	3,000	5,147
1 - Scheduled Outage	10,546	9,438	5,801	7,064	15,099	17,539
2 - Loss of Supply	15,678	25,747	30,181	14,153	0	1,949
3 - Tree Contacts	34,183	57,474	18,248	9,477	16,115	15,688
4 - Lightning	958	1,562	10,999	2,482	1,911	8,567
5 - Defective Equipment	17,096	15,795	15,372	10,289	19,430	24,015
6 - Adverse Weather	78,907	12,252	567	86	138	28
7 - Adverse Environment	14,110	100	1	469	585	0
8 - Human Element	419	285	106	293	1,875	139
9 - Foreign Interference	21,950	19,345	18,455	10,813	14,537	8,387
10- Major Event	78,958	0	0	0	0	0

b) SNC categorizes events by standard OEB outage categories with Defective Equipment shown in the above table.

2-AMPCO-12

Ref: Ex 2 Appendix 2-A p. 37

SNC customers have experienced an average annual improvement in SAIDI (all causes) of 12%, and average improvement in SAIFI (all causes) of 6% over the historical period.

Please provide the forecast performance of SAIDI and SAIFI over the forecast period 2024 to 2028.

SNC Response:

SNC's proposed investments are targeted at maintaining the current level of performance with respect to SAIDI (at or below 1.77) and SAIFI (at or below 2.49) over the forecast period

2-AMPCO-13

Ref: Ex 2 Appendix 2-A p. 42

With respect to Pole Testing, in 2019 SNC began a program to systematically test the remaining strength at the ground line of its wood pole population.

a) Please explain how the test is conducted.
b) Please confirm pole testing is undertaken in Thunder Bay and Kenora service territories.
c) Please provide the number of poles tested each year for the period 2019 to 2022 and forecast for 2023 to 2028.
d) Please provide the Pole Testing costs for each year for the period 2019 to 2022 and forecast for 2023 to 2028.
e) Please provide the Pole Testing results for the period 2019 to 2022.

SNC Response:

a) Wood poles are field tested using a non-destructive device which measures the remaining strength of the wood pole at the groundline. The tool is used to take multiple measurements at the groundline, and the software calculates an empirical value of the remaining strength based on measurement angle, density profile, and moisture content.
b) Pole testing has taken place in Thunder Bay since 2019. Pole testing for the entire population was completed in 2015/2016 in Kenora and is scheduled to take place in 2025 as part of its regular inspection cycle.
c) Please see Table 2-24 below.

TABLE 2-24: POLE TESTING COUNTS

Year	Quantity
2019	1226
2020	1197
2021	1196
2022	1186
2023	1200
2024	1200
2025	1650
2026	1200
2027	1200
2028	1650

d) Please see Table 2-25 below.

TABLE 2-25: POLE TESTING COST

Year	Cost
2019	$21,796
2020	$27,728
2021	$27,705
2022	$27,473
2023	$27,798
2024	$28,631
2025	$39,304
2026	$29,788
2027	$30,384
2028	$41,792

e) The testing is discussed in the Material Investment Report (Exhibit 2, Appendix 2-A, starting at page 460/716), with specific results on pages 467 & 468 of 716 pgs. 2-AMPCO-14

2-AMPCO-14

Ref: Ex 2 Appendix 2-A p. 42

With respect to Cable Testing, in 2020 SNC began non-destructive cable testing in several areas throughout Thunder Bay.

a) Please explain how the test is conducted.
b) Please confirm pole testing is undertaken in Thunder Bay and Kenora service territories.
c) Please provide the km tested each year for the period 2019 to 2022 and forecast for 2023 to 2028.
d) Please provide the Cable Testing costs for each year for the period 2019 to 2022 and forecast for 2023 to 2028.
e) Please provide the Cable Testing results for the period 2019 to 2022.

<u>SNC Response:</u>

a) Cable testing is performed using an on-site diagnostic tool that measures the DC (direct current) depolarization current within an isolated and de-energized cable. The test determines the extent to which water trees have degraded the insulation, which is one of the main aging mechanisms for underground cable.
b) SNC has assumed based on the reference that the question intended to have cable testing in place of pole testing. Cable testing has been conducted in both Thunder Bay and Kenora.
c) Please see Table 2-26 below.

TABLE 2-26: CABLE TESTING – KM TESTED PER YEAR

Year	Quantity (km.)
2019	Cable testing began in 2020
2020	12
2021	25
2022	20
2023	26
2024	20
2025	20
2026	20
2027	20
2028	20

d) Please see Table 2-27 below.

TABLE 2-27: CABLE TESTING COSTS PER YEAR

Year	Cost
2019	Not applicable
2020	$32,112
2021	$104,358
2022	$70,184
2023	$70,681
2024	$72,095
2025	$75,007
2026	$76,507
2027	$78,038
2028	$79,598

e) Results of the testing are shown in Exhibit 2, Appendix 2-A page 524.

2-AMPCO-15

Ref: Ex 2 Appendix 2-A p. 56

SNC tracks feeder performance as a composite of all OEB defined outage categories; as well individually by OEB outage category and trends feeder performance overtime. By analyzing the data SNC can identify the poorest performing feeders annually, as well as feeders that have continually performed poorly. Feeder performance is further analyzed to determine how current programs will impact these statistics and consideration to this fact is given at the time of selecting and prioritizing projects.

Please summarize SNC's current analysis with respect to poorest performing feeders and provide SNC's plans to address feeder performance in the 2024-2028 investment plan.

SNC Response:

SNC's current analysis uses data obtained from the SCADA system which provides details regarding each outage, its duration, how many customers are affected and the cause of the outage (by OEB cause code). The analysis then graphs the cause codes by the worst performing feeders and determines if there are any trends that can be identified on a particular feeder based on cause codes. SNC has a target to complete one feeder study annually and provide recommendations on improvements for the coordination of protective devices such as fuses and breakers and to recommend the optimal locations for reclosers on a feeder. The worst performing feeders from the above analysis are chosen for the feeder studies.

In the 2024-2028 period, SNC has budgeted to install 3 reclosers annually to address feeder performance across both its service territories. The feeder study performed in 2023 was for Kenora Feeder A and one mid-feeder recloser is planned in 2024. Another two reclosers will be deployed for feeders selected from a feeder study in the first quarter of 2024 based on 2023 outage statistics.

2-AMPCO-16

Ref: Ex 2 Appendix 2-A p. 56

SNC utilizes financial metrics on a per unit basis for its major asset categories based on actual historical replacement to estimate future capital costs for projects of similar size and scope. These metrics are updated annually to ensure that the estimating process continues to be effective and is based on the best available data each year.

Ref: Ex 2 Appendix 2-A p. 94

SNC maintains a repository of information regarding its previously completed projects. Metrics for these projects are tracked to assist in future budgeting efforts. Data is tracked in the form of dollars as well as labour hours on a per unit basis to estimate projects costs based on the scope defined in the project listing.

Please provide SNC's financial metrics for its major asset categories for the period 2017 to 2022.

SNC Response:

Please see response to 2-Staff-34.

2-AMPCO-17

Ref: Ex 2 Appendix 2-A p. 62

In anticipation of KMTS reaching its thermal capacity, SNC has retained the services of Power Advisory Group to provide options for managing this peak demand.

Please provide the report prepared by Power Advisory Group.

SNC Response:

The report prepared by Power Advisory Group is included as Attachment 2-2: Power Advisory Group Report.

2-AMPCO-18

Ref: Ex 2 Appendix 2-A p. 62

Table 5.3-7 summarizes the approximate number of major distribution assets within SNC's service territory.

a) For each asset category, please provide the quantity of assets replaced over the period 2017 to 2022.

b) For each asset category, please provide the quantity of assets to be replaced in 2024.

SNC Response:

a & b) Please see Table 2-28 below Assets Actioned 2017-2024.

TABLE 2-28: ASSETS ACTIONED 2017-2024

	Station Transformers		Breakers	Wood Poles	Distribution Transformers			OH Switches							Underground Switches	Underground Cables	
	4 kV	12 kV	Breakers	All Wood Poles	Pad Mounted Transformers	Pole Mounted Transformers	Vault Transformers	4kV In-Line	4kV Manual Air Break	12 and 25kV In-Line	12 and 25kV Manual Air Break	115kV Air Break	25kV Motorized Load Break	Reclosers	25kV Underground Load Break Switches	4kV	12 and 25kV
2017 Assets Actioned	1	0	5	432	59	116	6	18	0	12	14	0	0	0	0	0.6	1.8
2018 Assets Actioned	1	0	5	432	33	158	0	10	2	17	3	0	2	7	0	0.9	2.8
2019 Assets Actioned	1	0	9	463	39	116	0	0	0	17	3	0	0	1	0	1.4	3.5
2020 Assets Actioned	0	0	0	535	14	112	3	12	0	7	4	0	0	0	0	0.5	0.4
2021 Assets Actioned	0	0	0	465	61	154	3	16	1	7	1	0	0	1	0	1.7	4.9
2022 Assets Actioned	0	0	0	509	21	91	3	12	1	13	3	0	0	3	0	0.9	2.1
2024 Proposed Assets to be Actioned	1	0	4	440	67	83	5	15	0	11	2	0	0	3	0	2.3	3.5

2-AMPCO-19

Ref: Ex 2 Appendix 2-A p. 108

Please provide Table 5.4-6 for the years 2017 to 2023.

SNC Response:

Please see Table 2-29 below.

TABLE 2-29: GROSS SYSTEM RENEWAL EXPENDITURES 2017-2023

System Renewal	Historical Period							Total $'000	Percent of Total
	2017 $'000	2018 $'000	2019 $'000	2020 $'000	2021 $'000	2022 $'000	2023 $'000		
4kV Conversions	5,973	4,873	3,612	4,949	5,632	3,008	5,028	33,075	52%
Overhead Renewal	172	1,274	1,642	1,066	824	4,557	2,610	12,146	19%
Underground Renewal	4	427	811	19	1,044	1,067	500	3,873	6%
Smal Pole Replacements	564	314	422	258	128	27	614	2,328	4%
Safety Reports	644	789	1,066	910	1,445	842	1,268	6,965	11%
Transformers/Switches	990	672	781	662	598	808	868	5,378	8%
Gross Capital	8,348	8,350	8,335	7,864	9,672	10,310	10,888	63,765	100%

2-AMPCO-20

Ref: Appendix 2-AA

a) Please explain and provide a breakdown of the capital tree trimming work in 2023 and 2024.

b) Please explain the driver for the increase in Small Pole Replacements in 2024 compared to the average spend over the 2017 to 2022 period.

c) Please explain the driver for the increase in Transformer/Switch/Switchgear Replacements in 2024 compared to the average spend over the 2017 to 2022 period.

d) Please explain the driver for the increase in Design Work in 2024 compared to the average spend over the 2017 to 2022 period.

e) Please explain the driver for the increase in Grid Modernization in 2024 compared to the average spend over the 2017 to 2022 period.

SNC Response:

a) Please refer to 2.0-VECC-6.

b) The drivers for the increase in Small Pole replacements can be found on page 493 of 716 in Ex. 2, Attachment 2-A - Material Investment Report, System Renewal, Small Pole Replacement "The increase proposed in this program for the test year and beyond is as a direct result of the inspection program that occurred in 2022 and identified assets in poor condition requiring replacement." Additionally, Page 494 of 716 provides an overview of the program and drivers.

c) The driver for the increase in Transformer/Switch/Switchgear is a direct result of the cost of Pad Mount Transformers increasing in cost by an average of 75% on the most common units ordered by SNC from 2022 to 2023 due to the significant cost increase of core materials. (Page 115 of the DSP).

d) The design work associated with a given project is capitalized with that specific project when it is completed, and therefore there is typically not aggregated total in "Design Work" for the historical period 2017 through 2022.

e) The expenditure in 2024 is the forecast total for all projects and gives the appearance of an increase when compared to the average over the 2017 to 2022 period for the aforementioned reason. However, the actual costs for design work have remained relatively stable in 2024 as compared to the historical period.

   The primary driver for the increase in grid modernization from the historical period is that SNC seeks to continue to find improvements in operational efficiency and cost-effectiveness by eliminating or reducing the need for manual switching as stated in Exhibit 2, Attachment 2-A Page 568 of 716 of the Material Investment Report, System Service, Grid Modernization.

VULNERABLE ENERGY CONSUMERS COALITION (VECC)

2.0-VECC -6

Reference: Exhibit 2, Appendix 2-AA

a) Please explain why "Tree Trimming" amounts of $700K (2023) and $417K (2024) appear in Appendix 2-AA -capital related reporting - and clarify whether it is SNC's proposal to capitalize tree trimming expenditures.

SNC response:

a) Tree trimming costs of $700K (2023) and $417K (2024) appear in Appendix 2-AA as SNC is following IFRS, IAS 16 Property Plant and Equipment rules which allow site preparation costs to be capitalized as a directly attributable cost. SNC performs tree trimming in capital rebuild areas where trimming is required to obtain access to infrastructure where trees have inhibited access to construction. It is SNC's historical practice to capitalize the site preparation (tree trimming) costs required within in each capital project.

2.0-VECC -7

Reference: Exhibit 2, Appendix 2-AA & Table 2-26

a) Please update Appendix 2-AA to show 2023 actuals and in a separate column the current forecasted year-end expenditures for 2023.
b) Please update Table 2-26 to show the updated 2023 results as shown in the response to a).

SNC response:

a) Please refer to the revised live Excel file, SNC_2024_Chapter2_Appendices_20231110 with the additional columns added to Appendix 2-AA to show both the year-to-date actuals for 2023 as well as forecasted year-end expenditures for 2023, which include 9 months of actual data.

b) Please see the following Table 2-30 (updated);

TABLE 2-30: UPDATED TABLE 2-26 TO REFLECT 2023 FORECAST

Line No.	USoA	Description	2023 Bridge	2024 Projected	Variance
1	**Intangible Plant**				
2	1609	Capital Contribution Pd - Gate Stn	$1,272,321	$1,272,321	$0
3	**Sub-total**		**$1,272,321**	**$1,272,321**	**$0**
4	**Distribution Plant**				
5	1805	Land	$148,673	$148,673	$0
6	1806	Land Rights	$0	$0	$0
7	1808	Buildings and Fixtures	$8,557,119	$8,712,369	$155,250
8	1810	Leasehold Improvements	$340,532	$340,532	$0
9	1815	Transformer Station Equipment > 50 kV	$2,842,894	$2,842,894	$0
10	1820	Distribution Station Equipment < 50 kV	$8,503,545	$8,503,545	$0
11	1830	Poles, Towers and Fixtures	$83,292,635	$87,341,355	$4,048,720
12	1835	Overhead Conductors and Devices	$59,518,557	$64,134,042	$4,615,485
13	1840	Underground Conduit	$20,039,436	$20,364,582	$325,146
14	1845	Underground Conductors and Devices	$27,446,252	$28,060,866	$614,614
15	1850	Line Transformers	$43,867,855	$45,973,147	$2,105,293
16	1855	Services (Overhead & Underground)	$24,275,723	$24,903,917	$628,195
17	1860	Meters	$13,266,818	$13,534,728	$267,910
18	**Sub-total**		**$292,100,039**	**$304,860,651**	**$12,760,612**
19	**General Plant**				
20	1915	Office Furniture and Equipment	$1,837,986	$1,888,986	$51,000
21	1920	Computer Equipment - Hardware	$5,267,457	$5,487,457	$220,000
22	1611	Computer Software	$1,625,104	$1,710,104	$85,000
23	1930	Transportation Equipment	$9,968,980	$10,568,980	$600,000
24	1935	Stores Equipment	$112,364	$112,364	$0
25	1940	Tools, Shop and Garage Equipment	$3,701,994	$3,821,994	$120,000
26	1945	Measurement and Testing Equipment	$677,634	$728,804	$51,170
27	1950	Power Operated Equipment	$425,791	$425,791	$0
28	1955	Communication Equipment	$533,274	$533,274	$0
29	1980	System Supervisory Equipment	$2,070,531	$2,334,612	$264,081
30	**Sub-total**		**$26,221,115**	**$27,612,366**	**$1,391,251**
31	**Contribution and Grants**				
32	1995	Contributions and Grants	($18,542,289)	($18,542,289)	$0
33	2440	Deferred Revenue	($23,650,630)	($25,185,052)	($1,534,422)
34	**Sub-total**		($42,192,919)	**($43,727,341)**	**($1,534,422)**
35	**Grand Total**		**$277,400,556**	**$290,017,996**	**$12,617,441**

2.0-VECC -8

Reference: Exhibit 2, pages 73

a) Please explain the need to replace the relatively new (2015) drop bow boat at $250,000.
b) Is this craft used both in the Kenora and Thunder Bay rate zones?

SNC response:

a) SNC services several islands on Lake of the Woods; the boat that is currently being used to service these islands is a recreational fishing boat (1925 open bow King Fisher). This boat is not designed for commercial/ construction use. It is not designed to transport equipment, material, climbing gear, or safety equipment that is required to restore power or perform routine work. The boat currently in use by SNC does not have a drop-down bow to unload on shorelines where SNC has infrastructure and where there is no customer dock to unload material. The style and design of the proposed new boat will ensure that SNC can safely transport staff, equipment, material, climbing gear, and safety equipment during all hours and in storm conditions. SNC engaged with another utility that uses this boat to ensure it was the right purchase to meet our needs.
b) This craft will only be used in the Kenora rate zone.

2.0-VECC -9

Reference: Exhibit 2, Appendix 2-A DSP page 8, Section 5.4.1.1

Table 5.2-1 Historical Actual and Forecast CAPEX and OM&A ($,000)

Category	Historical Period						Bridge Year	Forecast Period			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
System Access (Gross)	1,942	1,688	4,370	3,299	3,383	4,066	1,985	2,092	4,323	2,796	2,4
System Renewal (Gross)	8,748	9,403	8,636	8,674	10,205	11,451	11,985	12,714	12,383	12,068	12,1
System Service (Gross)	151	289	432	87	242	142	277	323	330	336	3
General Plant (Gross)	929	1,093	1,073	863	1,273	1,529	1,174	1,282	1,480	1,473	1,6
Gross Capital Expenditure	11,770	12,473	14,510	12,924	15,104	17,188	15,420	16,411	18,516	16,674	16,5
Contributed Capital	(1,017)	(1,243)	(2,517)	(2,923)	(2,742)	(3,415)	(1,422)	(1,534)	(3,437)	(1,865)	(1,59
Net Capital Expenses after Contributions	10,754	11,230	11,993	10,001	12,362	13,772	13,999	14,877	15,079	14,809	14,9
System O&M	8,785	9,155	8,881	8,317	8,387	11,359	11,253	11,779	12,014	12,255	12,5

a) SNC is proposing to spend a significantly larger amount on system renewal and general plant in the 2024 to 2028 period than had historically been made over the 2017 to 2021 time frame. Please describe what fundamental changes in asset condition have occurred since the last distribution plan which justify this higher level of spending. Specifically address which category of assets significantly deteriorated over the last rate period and why the prior DSP failed to anticipate the capital needs for those assets.

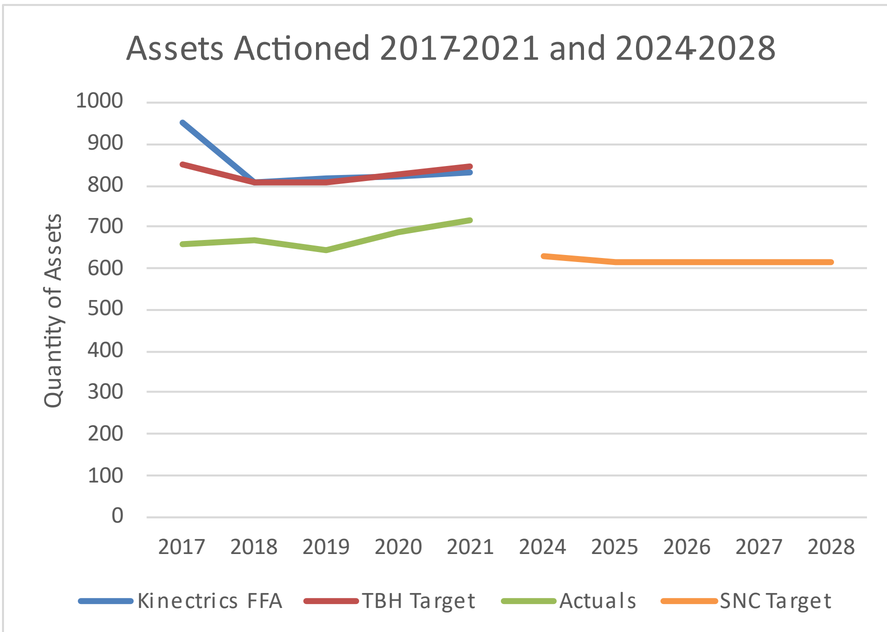
b) Table 5.4-3 – Summary of Changes to Capital Programs -shows for most areas of the DSP there have been no significant changes. Please clarify the extent to which the 4kV conversion program is a driver to the higher spending during the new rate period.

SNC response:

a) SNC has worked diligently to improve its asset condition assessment by undertaking and incorporating empirical testing as part of its inspection programs. While this has led to improved confidence in the output, SNC has not experienced significant deterioration or fundamental change in asset condition since its last filing.

For the following refer to the Chart below.

As part of its last filing, then Thunder Bay Hydro proposed a level of assets to be actioned that was closely aligned with the Kinectrics FFA (flagged-for-action) plan. However, the actual level of work accomplished was less than proposed, due largely to the results of the OEB decision[3] wherein Thunder Bay Hydro's proposed capital expenditure was reduced.



For the forecast period, SNC is proposing to action assets at or slightly below the average level achieved over the period 2017 through 2021. SNC has seen a fundamental increase in the price of resources, as well as an increase in the complexity required to execute its renewal programs and these are the primary drivers for the increase in spending. See the following excerpt from Exhibit 1:

[3] OEB Decision and Order, EB-2016-0105, Thunder Bay Hydro Electricity Distribution Inc.

1.4.16.4 Global Inflation

Canada's annual inflation rate in 2022 was 6.8%, the highest level seen since 1991. Over the last few years SNC has experienced significant inflationary increases on materials, goods, and services specifically related to its capital and operating costs. Some examples of cost increases SNC has experienced are the following:

- There has been a 31% increase in the price of diesel fuel and 20% increase in gasoline fuel costs from 2021 to 2022 significantly impacting SNC's fleet costs;
- The cost for Pad mount transformers has increased by an average of 75% on the most common units ordered by SNC from 2022 to 2023 due to the significant cost increase of steel;
- The price of wood poles has increased by 17% from 2022 to 2023;
- Wire and Cable costs, manufactured out of copper and aluminum have increased by an average of 60% from 2021 to 2022.

Furthermore, SNC has seen a marked increase in the cost of fleet vehicles ranging from 20% to 91% as shown in the table below:

Table 2-1 Typical Purchase Price Historical vs Current

Category	2016 Price	2023 Price	Difference in Cost	% Difference
Light Truck	$ 39,009	$ 67,390	$ 28,381	73%
SUV	$ 31,771	$ 38,244	$ 6,473	20%
F-350	$ 42,085	$ 80,265	$ 38,180	91%
Single Bucket	$ 326,000	$ 510,000	$ 184,000	56%

In the forecast period SNC is working to mitigate costs to customers by reducing the fleet complement from 91 vehicles down to 75 and replacing only those vehicles that have deteriorated beyond repair. This, while still maintaining the ability to perform work and service customers.

b) As discussed in part a) of this question the main driver of the higher spending is not a planned larger scope of work, instead SNC is looking to complete its 4kV conversions as planned over the forecast horizon while slightly reducing the pacing of actioned assets to mitigate the cost increases being experienced on resourcing and labour.

2.0-VECC -10

Reference: Exhibit 2, Appendix 2-A DSP page 11

a) Please provide the amounts expended or budgeted for the underground renewal program for each year 2019 through 2024.

b) Please provide (separately) the amounts expended on new underground plant in each year 2019 through 2021.

c) What type of cabling does SNC install for new underground works and what type of cabling is typically addressed in its underground renewal program.

d) Please provide the total km of underground plant in service in each year 2019 through 2024.

SNC response:

a) Please see Table 2-31 below.

TABLE 2-31: UNDERGROUND RENEWAL PROGRAM CAPITAL EXPENDITURES - 2019 TO 2024

2019	2020	2021	2022	2023	2024
$811,303	$18,974	$1,044,342	$1,067,158	$500,000	$645,769

b) Please see Table 2-32 below.

TABLE 2-32: UNDERGROUND RENEWAL NEWLY INSTALLED PLANT CAPITAL EXPENDITURES – 2019 TO 2021

2019	2020	2021
$811,303	$18,974	$867,247

c) SNC installs tree-retardant, jacketed XLPE cables in duct for new underground works. SNC typically addresses direct buried, non-tree retardant, unjacketed XLPE cables as part of its underground renewal program.

d) Please see Table 2-33 below.

TABLE 2-33: TOTAL KM OF UNDERGROUND PLANT IN SERVICE- 2019 TO 2024

2019	2020	2021	2022	2023	2024
1,045	1,057	1,065	1,076	1,080	1,090

2.0-VECC -11

Reference: Exhibit 2, Appendix 2-A DSP – page 55

"An ACA study was originally completed by Kinectrics in 2015. Since then, the data has been updated and maintained by SNC staff to determine the current health of SNC's distribution system assets"

a) Please provide the above mentioned 2015 Kinectrics Study.
b) Since 2015 has SNC had any independent assessment made of any of its major asset classes?

SNC response:

a) Please see Attachment 2-3: 2015 Kinectrics Study
b) Since 2015 SNC has had third party, independent assessments for several of its major asset categories, specifically wood poles (testing and inspection), underground cables (testing) and pad mounted transformers (inspections).

2.0-VECC -12

Reference: Exhibit 2, Appendix 2-A DSP – page 55

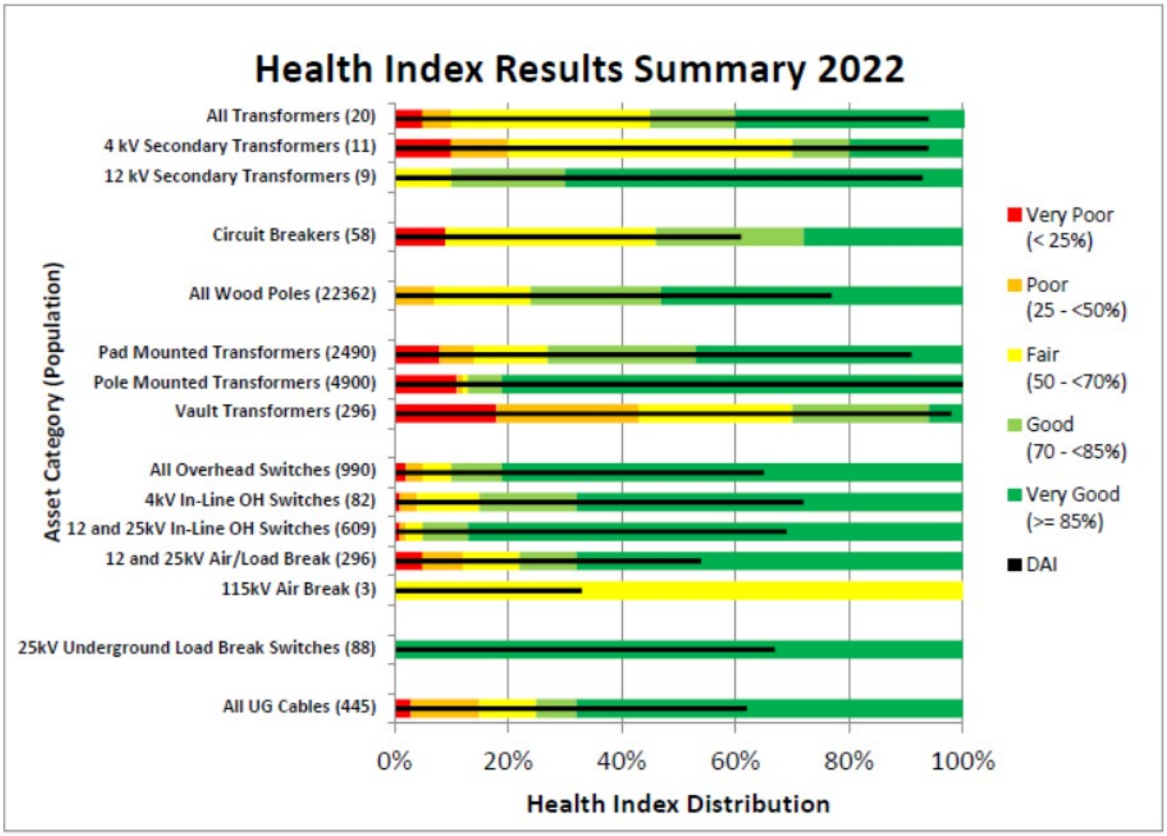


Figure 5.3-9 Health Index Summary

a) For each of the asset categories monitored by SNC please indicate what methods are used to determine asset condition (i.e., age, periodic physical testing, etc.). If a methodology other than age is used to determine condition (e.g., oil testing) please briefly describe the methodology, the frequency of testing and the percentage of the population that has been subject to testing within the last 5 years.

<u>SNC response:</u>

a) The methodology SNC uses to determine the condition of its assets is based on inspection and testing information collected in the field; age is not solely used to determine the condition of any asset category. The detailed inspection and maintenance practices for assets can be found in Section 5.3.3.3 of the DSP and describes the method and frequency of inspection.

The following table indicates which assets have had empirical testing and the percentage of the population tested.

Table 2-34: Asset Population with Testing Data

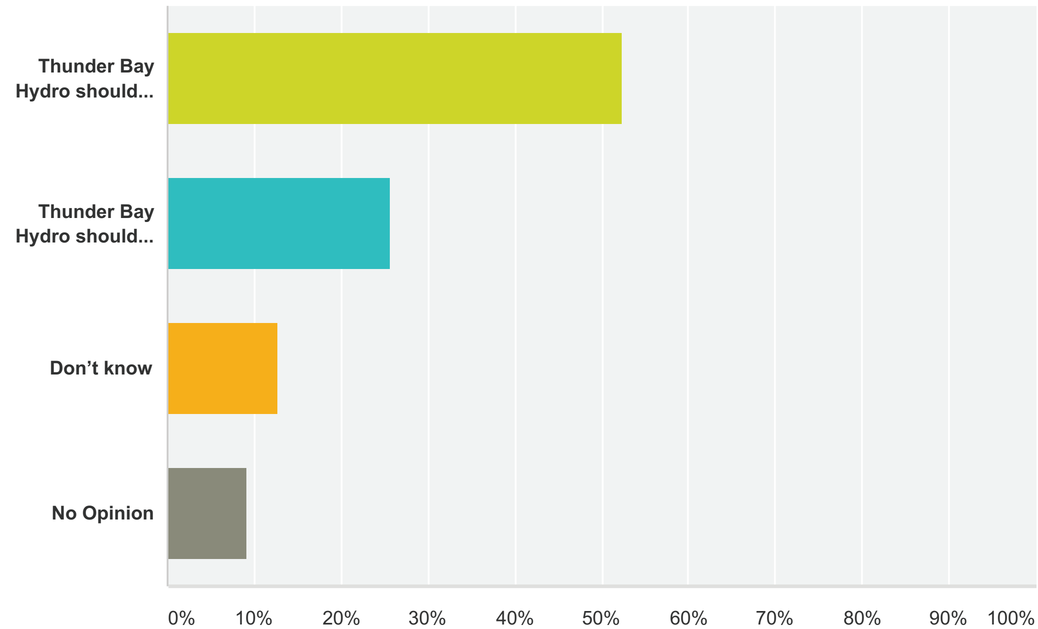
Asset	Percentage of Population Tested
4kV Station Transformers	100%
12kV Station Transformers	100%
Circuit Breakers	100%
Wood Poles	31%
Underground Cables	10%

ATTACHMENT 2-1:

Customer Survey

Q5 With regards to projects focused on replacing aging equipment in poor conditions, which of the following statements best represents your point of view?

Answered: 1,054 Skipped: 69



Answer Choices	Responses	
Thunder Bay Hydro should invest what it takes to replace the system's aging infrastructure to maintain system reliability, even if that increases my monthly electricity bill by a few dollars over the next few years.	**52.37%**	552
Thunder Bay Hydro should lower its investment in renewing the system's aging infrastructure to lessen the impact of any bill increase, even if that means more or longer power outages.	**25.71%**	271
Don't know	**12.71%**	134
No Opinion	**9.20%**	97
Total		**1,054**

ATTACHMENT 2-2:

Power Advisory Group Report

POWER ADVISORY

Supporting SYNERGY NORTH through a Distributed Energy Future

Prepared for SYNERGY NORTH

August 30, 2022

Overview

- Power Advisory was retained by SYNERGY NORTH to provide an overview and analysis of the changing regulatory framework for Distributed Energy Resources (DERs) in Ontario
- The analysis provides an assessment of opportunities for SYNERGY NORTH to consider DERs and activities being undertaken by other Local Distribution Companies (LDCs)
- The analysis also looks at regulated utility fleet electrification and utility-led public electric vehicle (EV) chargers in other jurisdictions and provide some insight to guide SYNERGY NORTH's proposed deployment of electric vehicles (EVs).
- EV uptake is also impacting system planning. The analysis includes an EV update forecast for SYNERGY NORTH's service area and options for managing peak demand growth.
- Further, Power Advisory considers the impact of DERs and EV uptake and opportunities to consider deployment of innovative energy storage resources to address reliability on the distribution assets with a focus on worst performing feeders and constrained stations (i.e., Kenora MTS)

Contents

Key Take-Aways for SYNERGY NORTH on DER Activities

- Overall, the deployment of DERs in Ontario is expected to grow rapidly over the next 5-7 years; the regulatory framework and services DERs can offer will evolve with the deployment and will requirement multiple processes and planning changes for SYNERGY NORTH

- Key Take-Aways for SYNERGY NORTH to consider as part of DER strategy
  - Electrification of transportation, space heating and industry is accelerating, likely increasing demand outlook within regions and straining regional and local power systems
  - Multiple initiatives underway to support integration of DERs into wholesale markets and regulatory framework
    - IESO Enabling Resources initiative is considering changes for market design, physical operation and coordination with LDCs
    - FEI report provides guidance on potential priorities for the OEB in the near future to incorporate DERs
  - In particular, the CDM guidelines update creates a clear opportunity for LDCs to explore services from DERs to meet reliability needs were applicable and with reasonable justification
    - While not driven by CDM guidelines, HONI's JRAP is the first large step towards requesting funding for NWS to enhancing reliability for customers; lessons learned from the Board's decision and direction will be critical for LDCs considering NWS in their service territory
  - Customer preference for renewable generation could change supply mix evolution and potential strain deliverability capability of transmission and distribution systems

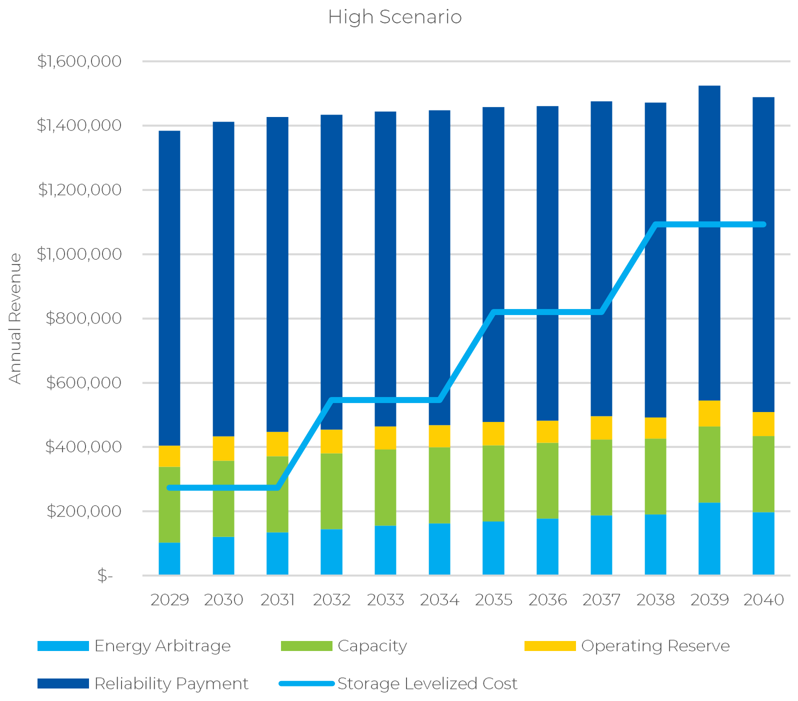
Summary and Next Steps for Energy Storage Deployment by SYNERGY NORTH

- Power Advisory's analysis of both energy storage deployment opportunities (i.e., Kenora MTS capital deferral and behind-the-meter (BTM) reliability enhancement) suggest that they may be more cost-effective than traditional wires investments
    - Kenora MTS energy storage can access many different services to reduce the cost of reliability service to Kenora; further, the project could be developed in stages to reduce cost and more closely align with load growth compared to a traditional large fixed investment in capacity
    - BTM energy storage offers reliability enhancement for end of radial line customers that previously did not have cost-effective options to enhance their reliability; particularly for short-to-momentary outages

- For BTM energy storage, Power Advisory proposes the following next steps
    - Identify a subset of customers that have experienced, or are expected to potentially experience, lower reliability performance due to their location on the distribution system topographic (e.g., end of long radial circuits)
    - Prepare an RFI for BTM energy storage deployment for reliability purposes to determine high-level cost, performance and other contractual provisions
    - RFI should also explore cost difference between aggregated contract (i.e., a contract with one entity to build/own/operate a fleet of BTM energy storage for reliability purposes) and customer incentives (i.e., fixed reliability service payment for customers that install BTM energy storage that are operated to enhance reliability

Summary and Next Steps for Energy Storage Deployment by SYNERGY NORTH (cont)

- For Kenora MTS energy storage, Power Advisory proposes the following next steps
  - Prepare a high-level cost estimate of the traditional wires investment (i.e., expanded station capacity) to assist in determining a reasonable reliability service payment threshold
  - Engage IESO to determine options to secure long-term capacity payments for the energy storage resource to support the province's resource adequacy needs
  - Assess the physical constraints at the station for development of an energy storage resource on current station site lands
  - Consider a Request for Information (RFI) to determine the potential cost, contract terms, and other provisions for a third-party to build/own/operate an energy storage resource to provide reliability services to SYNERGY NORTH



Summary and Next Steps for EV Charging and Fleet Electrification

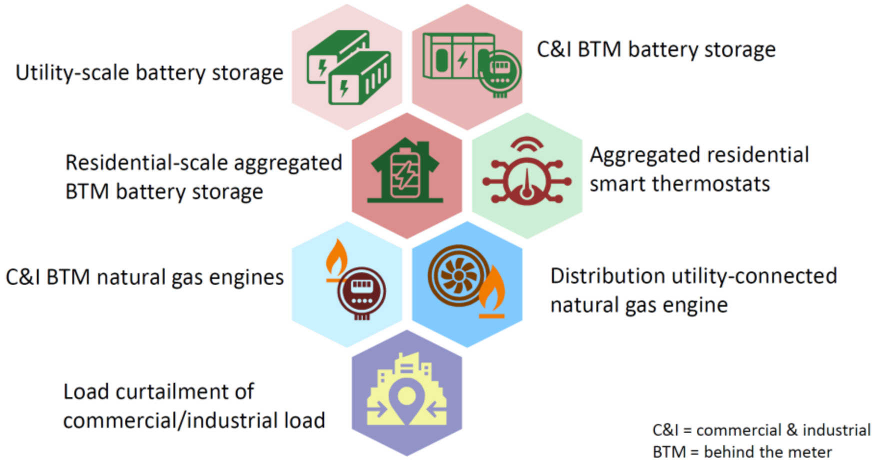
- Power Advisory suggests that more analytical work is needed to understand the effect of projected EV load on SYNERGY NORTH's system
- Immediate next steps include developing granular, internal forecasts of EV uptake instead of relying on IESO projections; system studies should identify areas which will soon need to be upgraded and areas that are currently best-suited for public charger development
- Further work on EV charging could include partnering with municipalities to support policy objectives and/or launching a local demand response pilot program
- On fleet electrification, lighter vehicles such as SUVs and half-ton trucks can be cost-effectively electrified with today's technology
- Power Advisory proposes that SYNERGY NORTH plan to purchase battery electric replacements for the oldest 2 to 3 light vehicles when they reach end of life
- Depending on how the existing fleet is utilized, there may be opportunities to electrify certain medium-duty vehicles
- For specialized vehicles (bucket trucks and RBDs), continue to monitor industry developments and demonstration projects

Overview of DER Activities in Ontario

Distributed Energy Resources

- Distributed Energy Resources (DERs) can provide services to wholesale electricity markets, electricity infrastructure (i.e., transmission and distribution network needs) and direct to customer benefits
- Given lower hurdles to permitting and shorter development timelines, Power Advisory expects DERs to be a rapidly growing share of new supply resources
- Integration into wholesale electricity markets are required as well as regulatory framework changes to support non-wires solutions (NWS) using DERs

Portfolio of Available DER Types



Source: Electric Power Research Institute

DER Assessment

- The IESO and the OEB recognize that technological innovation requires that the sector prepare for changes to the utility landscape driven by greater customer expectations and being able to choose options for managing electricity supplies and costs at the customer level

- The IESO is working through elements of its Distributed Energy Resources (DER) Roadmap and has laid out a workplan that runs through to 2026

    1. IESO is not expected to fully integrate DERs until post implementation of the Market Renewal Program (MRP), which is currently planned for 2026
    2. Partially due to MRP implementation, and Ontario's unique hybrid market design, new capacity will only be brought online with long-term contracts or rate-regulated revenue certainty
    3. DERs are most valuable when sited in areas where there are also transmission or distribution system needs

- In the immediate term, DERs are likely to be driven by LDCs/utilities to meet local power system needs and/or support customers seeking renewable resources for their ESG mandates

- Therefore, it is prudent for SYNERGY NORTH to plan and explore DER deployments to capture this value for customers and support municipal/provincial policy decisions

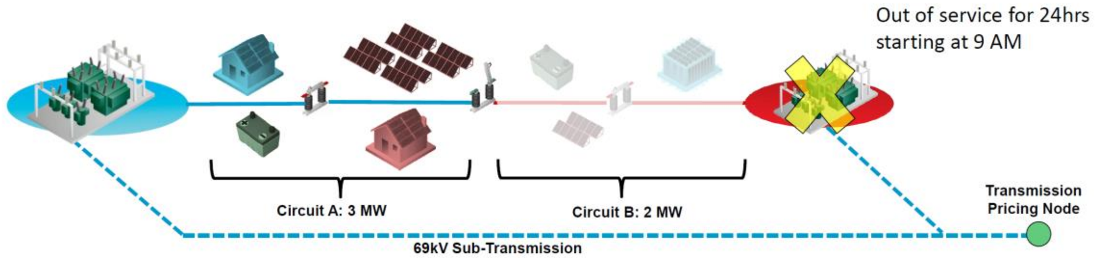
Enabling Resources Program

- The IESO has committed to produce and implement an integrated work plan that will outline the sequencing, timing and scope of activities to be undertaken by the IESO to enable existing electricity resources to provide electricity services in the post-MRP market that cannot be fully provided under the current market design

- Two priority enablement initiatives have been identified
  - Distributed Energy Resources (DERs): to support enabling DERs, the IESO has launched three different activities
    - DER Potential Study to determine the economic potential and value of DERs over the next decade (note that Power Advisory is part of the consulting team for the IESO)
    - DER Roadmap: establish IESO objectives, initiatives and time for DER integration based on stakeholder input and linked to other IESO ongoing initiatives
    - DER Market Vision: to explore new "foundational" participation models for DER integration into wholesale markets and identify the criteria for future models; followed by a DER Market Design Project that will design and implement the foundational participation model
  - Hybrid Integration Project: to identify participation model(s) to enable hybrid resources (e.g., solar + storage) in the IESO-Administered Markets and the capability to support Ontario's future system need
    - The Hybrid Integration Project has received additional support through the Minister's Directive to the IESO

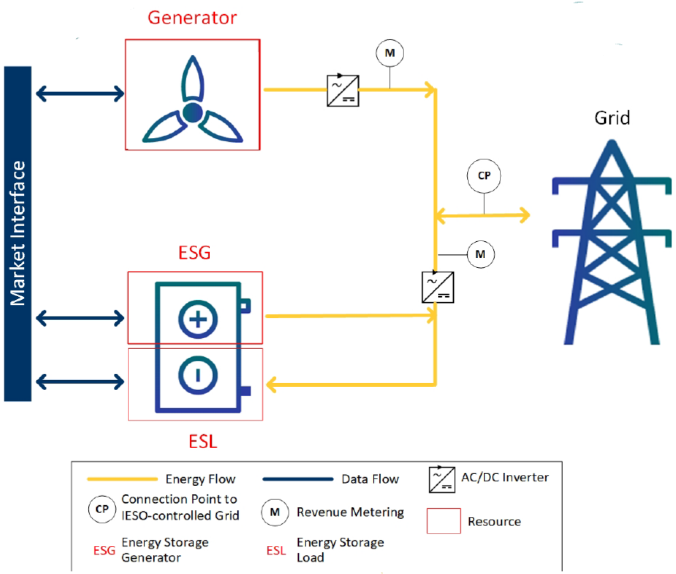
Transmission-Distribution Working Group (TDWG)

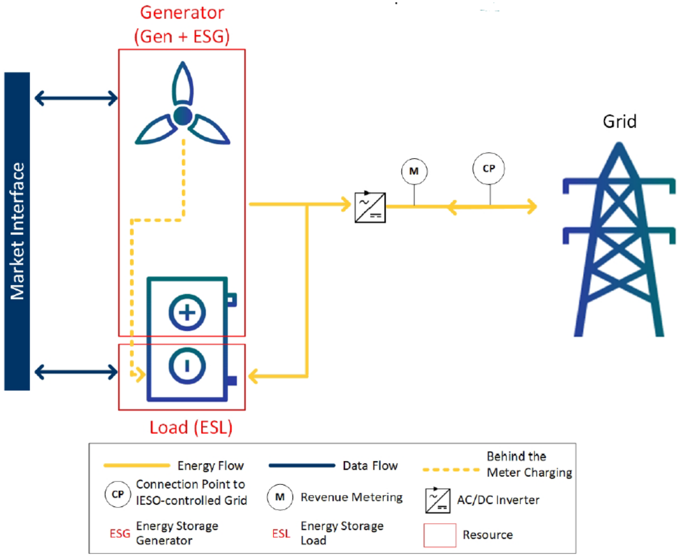
- In support of the enabling resources program, the IESO has launched the TDWG to explore coordination protocols for determining deliverability of DERs during real-time system operation
- As more resources connect to the distribution system and demand becomes more flexible due to emerging and innovative products; system planning and operation will need to change to maintain power quality standards throughout the provincial grid
- Real-time deliverability communication and management will be critical for urban centers that have high load concentrations and strained delivery networks
- SYNERGY NORTH will benefit from the learnings and protocols established by the Transmission Distribution Coordination Working Group to understand the potential for DERs and CDM to be incorporated into planning and real-time operation



Source: ESIG

Hybrid Integration Project

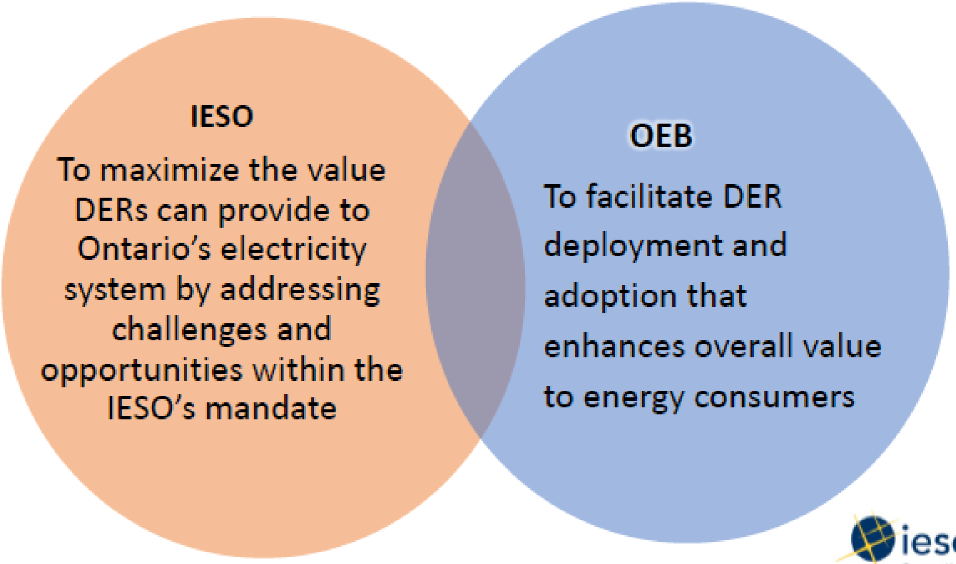




- The IESO is proposing two hybrid participation models for storage + generation: Co-located (left) and Integrated (right)
- Both participation models are reasonable interim solutions for hybrid facilities and leverage the existing IESO market tools thereby avoiding the need for time consuming investments during the MRP process

DER Assessment – OEB DER Integration

- The OEB is working closely with the IESO on leading a stakeholder engagement on DER Integration through its Joint Engagement on DER Integration



OEB Framework for Energy Innovation

- For the past few years, the OEB has been holding discussions with stakeholders on regulatory framework changes needed to address distribution system evolution through two joint policy consultations: Utility Remuneration and Responding to Distributed Energy Resources (DERs) (UR/RDER)

- In March 2021, the OEB announced a new policy consultation to replace the UR/RDER, the Framework for Energy Innovation (FEI); immediate priority will be addressed as part of two workstreams:
    - Workstream #1 – DER Usage: Investigating and supporting utilities use of DERs they do not own as non-wires solutions (e.g., use cases, measuring benefits, appropriate incentives, etc.)
    - Workstream #2 – DER Integration: Informing utility planning (e.g., existing DERs, DER forecasts, reporting requirements, etc.)

- The OEB has established a FEI Working Group of 22 members across the stakeholder spectrum (e.g., utilities, DER providers, consumers, environmental organizations)
    - Power Advisory has been granted observer status for the FEI working group

OEB FEI Working Group Next Steps

- The FEI Working Group issued a report in June 2022 that provided a summary of its activities and providing potential next steps for the OEB to consider as part of integrating and supporting DERs in Ontario's distribution systems
  - Provide further guidance on the role and expectations of distributors
  - Actively engage in the broader energy sector policy development activities
  - Establish an initial framework and template for benefit cost analysis
  - Remove DER disincentives including cost recovery uncertainties
  - Establish an initial DER incentives policy including testing possible incentive structures
  - Establish an initial policy for sharing of information between LDCs, DER providers, and customers to support distribution system planning and operations
  - Develop regulatory reporting requirements for DERs, including RRR filings, applications, and other OEB reporting
- Power Advisory believes the next steps recommended by the FEI Working Group are appropriate and point in the right direction; however, the working group process is limited in its ability to move fast enough for the sector
- Power Advisory strongly recommends that an adjudicated process is required to determine the appropriate changes to the regulatory framework in Ontario to maximize the benefits of DERs, support net-zero objectives and manage costs for customers

Conservation & Demand Management

- The 2021-2024 Conservation & Demand Management (CDM) Framework reduces the scope of CDM in the province
  - The framework has a budget of $692 million and targets 440 MW of peak demand savings and 2.7 TWh of electricity savings
- The role of LDCs is reduced under the 2021-2024 CDM Framework with a focus on partnerships with the IESO to deliver local initiatives programs
  - Four areas are initially targeted: Richview South in Toronto, York Region, Ottawa, and Belle River
- The 2021-2024 CDM Framework was launched prior to the latest update by the IESO on resource adequacy needs and the large expansion of procurement targets
  - As such, the objectives of the 2021-2024 CDM Framework do not align with the broader power system needs

Update to OEB CDM Guidelines

- In December 2021, the OEB issued updated guidance on the role of CDM activities for rate-regulated electricity distributors (i.e., LDCs) that reflect the evolution of CDM through various provincial CDM frameworks as well as the vast expansion of CDM services that can be offered from emerging and innovative technologies

- While the 2021-2024 CDM Framework reduced the role of LDCs in the delivery of CDM, the OEB CDM guidelines have provided a path to greatly expand the deployment of CDM to meet distribution system needs and manage delivery costs for Ontario rate payers
  - The OEB expanded the definition of CDM activities to include any activity that manages energy consumption or provides energy savings; this change greatly opens up the options for CDM and provides sufficient flexibility for LDCs to incorporate new CDM service offerings into their service territory
  - Non-distributor owned behind-the-meter resources can also offer CDM activities, a significant recognition of the growing capabilities of customers to support the distribution system and offer flexible demand services
  - CDM activities are expected to be part of local distribution system planning and regional planning processes; in short, CDM services should be a critical part of any integrated planning process for both temporary solutions (e.g., to manage load growth while large infrastructure is being developed) and permanent solutions (e.g., demand shifting to eliminate overloading of distribution equipment)

- As discussed on the following slides, the rapid growth of Distributed Energy Resources as part of CDM activities will fundamentally change power system planning and investment decisions; CDM will be a critical component in a net-zero future

Customer programs to Manage Electricity Costs Continue to Change

- Industrial Conservation Incentive (ICI) continues to be controversial
    - Given concerns during pandemic, in June 2020 Ontario government announced temporary pause on ICI
    - 2020 Ontario budget announced that out-of-market costs for contracted renewable energy would be subsidized by the tax-base, therefore reducing Global Adjustment (GA) and incentive to participate in ICI
- Ontario proposing a new Interruptible Rate Pilot program for large consumers as alternative to ICI
    - Consideration of new rate design that would remove some of the uncertainty for customers participating in ICI
- 2021-2024 CDM Framework significantly scaled back responsibilities of distributors compared to previous framework
    - Current programs are centrally administered, and include retrofit program, small business, energy managers, energy performance, energy affordability program and programs for Indigenous communities
    - IESO moving to competitive processes for industrial energy efficiency
    - Mid-term review expected to ramp up CDM given pending supply crunch in Ontario
- Power Advisory views significant opportunity for LDC-led initiatives that support customer affordability and services to bulk system (e.g., reduced energy and capacity supply requirements)

Fundamental Redesign of Wholesale Market

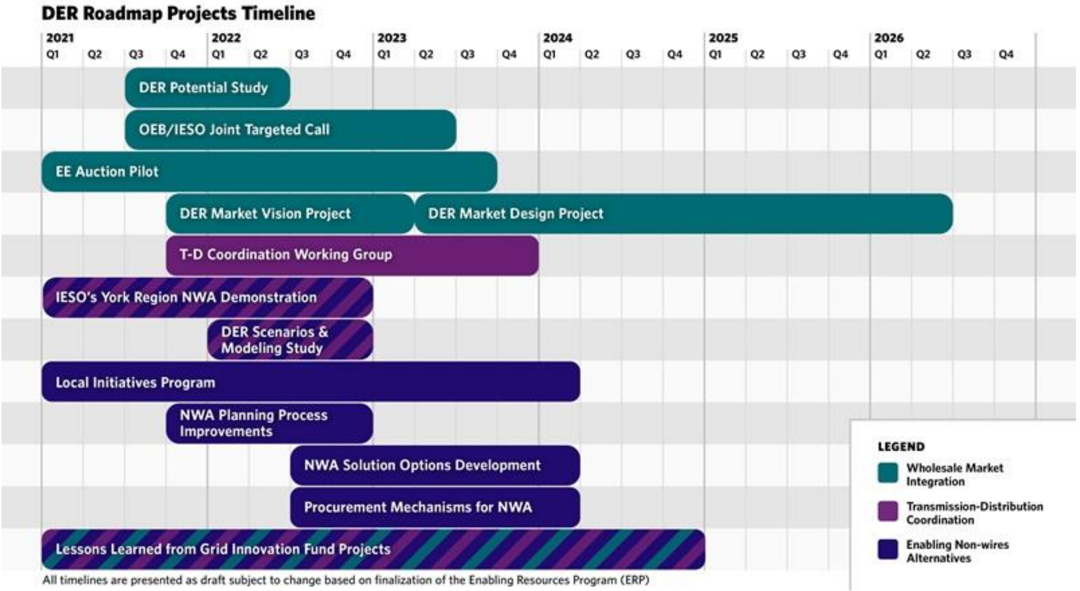
- IESO launched the Market Renewal Program (MRP) in 2017 to improve efficiency of wholesale electricity market and enable competition for technology neutral supply to meet needs
- Business Case for MRP Energy completed in 2019 indicated upward of $1 Billion in savings over 10-years; IESO estimates cost to implement MRP to be ~$170 Million
    - IESO estimated the net present value of MRP Energy to be between $290 Million and $450 Million
- MRP Energy is consistent with U.S. Standard Market Design, including:
    - Implementation of Locational Marginal Prices (LMPs) for energy and operating reserve
    - Introduction of a financially-binding Day-Ahead Market (DAM)
    - Changes to unit commitment processes from day-ahead through to real-time
- IESO's current schedule indicates MRP will "go-live" November 2023; however, Power Advisory believes there is a high likelihood for delay and schedule revisions
- To implement MRP, several changes to OEB's regulatory instruments will be required, including changes to Retail Settlement Code, Distribution System Code, Accounting Handbook, etc.

MRP Implementation Impacts LDCs

- IESO's MRP is the most significant reform to the wholesale market since market opening
  - MRP has become a "destiny" issue for IESO, with significant internal resources being dedicated to effect the program
- Some of the specific reforms outlined in the MRP detailed design documents are continually being assessed by specific segments of Market Participants, for example:
  - New dispatch data parameters for some hydroelectric generators
  - Revisions to scheduling gas-fired generators with contractual implications
  - For all customers, particularly so for industrial customers, lack of definition of Global Adjustment and allocation of these charges based on planned implementation of LMP
- MRP will require an extensive period of rule amendments and industry training and preparedness for new tools and processes
  - This means resources within LDCs will need to be dedicated to implement new wholesale market settlement systems and regulatory processes (e.g., regulatory accounting, etc.)
- Risk that MRP will be delayed/overbudget due to Market Participant concerns (costs, lost revenue, etc.) if Market Participant(s) file for OEB review (appeal) of Market Rule amendments

Integrating DERs in Wholesale Market

- Several IESO initiatives to integrated DERs and storage, but processes take several years
    - Ontario has opportunity to learn from other markets given FERC Order 2222 implementation
- IESO does not plan to make significant tool changes to further integrate DERs and energy storage until at least 2026
    - MRP viewed by IESO as higher priority
- IESO has established a series of working groups, stakeholder engagements, and studies to evaluate DERs and options for enhancements
- For LDCs, it will be important to track, participate, influence these activities given expected DER connections



Source: IESO

Case Study Examples of DER Deployment

Hydro One Joint Rate Application (JRAP)

- In August 2021, Hydro One filed its 2023-2027 transmission and distribution investment plan, the “Joint Rate Application” or JRAP
- The JRAP proposes approximately $1.5b in transmission and $1.0b in distribution capital investments annually over the 5 year
    - The plan includes renewing high voltage power lines, replacing transformers and wood pole replacement
    - Increasing automation on distribution infrastructure and installing smart devices to improve resiliency for customers with the most power outages
    - Invest in new or upgraded infrastructure to accommodate new customers
    - Install innovative energy battery storage solutions to improve resiliency
        - This category of investment is expected to result in grid connected battery storage in isolated communities to enhance reliability and address frequent outages.
        - Hydro One is also proposing to deploy 2,000 small-scale customer based behind the meter storage projects on poor feeders or approximately 400 targeted projects per year
- Overall, the JRAP is the first firm large request for rate-regulated recovery of energy storage assets for reliability purposes and will likely be a benchmark for future LDC rate-recovery requests

Lakeland Power's SPEEDIER Project

- The town of Parry Sound and Lakeland Power deployed a DERs solution to address the grid constraint on the Parry Sound TS that was limiting economic growth in the community.

- The project involves the installation of:
  - A 500 kW solar array
  - 1.26 MW 2.51 MWH Tesla Megapack battery energy storage
  - Residential scale Tesla Powerwalls
  - Domestic hot water smart thermostats
  - EV chargers – 1 Level 3 and 3 Level 2 chargers
  - A microgrid that can island and operate independent of the provincial grid

- The project is near completion and received funding from NRCan to demonstrate the ability of advanced grid modeling and system planning tools as well as Distributed Energy Resource Management (DERMS) for increasing visibility and control of loads and variable renewable generation.

- The project addresses previously identified needs for costly system upgrades required for the growing energy demands of the community.

Arizona Public Service (APS)

- The town of Punkin Center, Arizona experienced thermal constraints on its 26 km supply feeder limiting load growth and expansion of economic activity
- Instead of rebuilding the distribution lines over rough terrain, battery energy storage system was installed
- The 2 MW / 8 MWh storage system was installed in the community to address the thermal constraint as a feasible NWA.
- This DER project was a cost-effective solution for APS to serve the rural community, compared to reconductoring of the line.
- The battery energy storage project was designed with the capability to add energy capacity as the need arises over the next five to 10 years.

New York ISO DER Participation Models

- New York is a North American leader launching its Reforming the Energy Vision in 2014 and advancing policy to enable DERs that may offer some insight into precedent expected to be adopted in Ontario

NYISO Participation Models

Resource Technology Type	Generator	Energy Storage	Load Curtailment - Demand Side Resources (DSR)	Generator + Storage	Mixed Technology - DER
Participation Models	Generator – for thermal generators and large hydro	Energy Storage Resources (ESR)	Demand Response (DR) – for non-dispatchable curtailment/load reduction	Co-located Storage Resource (CSR) – for separate IPR & ESR w/ shared interconnection	Dispatchable Distributed Energy Resource (DER) – for a facility or aggregation with mixed resource technologies (to be implemented by the end of 2022).
	Intermittent Power Resources (IPR) – for wind and solar	Limited Energy Storage Resource (LESR) – for Regulation-only storage like flywheels	Dispatchable Distributed Energy Resource (DER) – for curtailment that is dispatchable (to be implemented by the end of 2022).	Hybrid Storage Resource – under development for a renewable and storage as one resource	Behind-the-Meter Net Generation (BTM:NG) – for a facility comprised of a Generator and a Host Load.
	Other models include – Run-of-River Hydro, Behind-the-meter Net Generator (BTM:NG)	Energy Limited Resources (ELR) – for pumped hydro			

New York ISO DER Available Service Provision

- New York has determined that DERs can provide certain services to the wholesale market and continues to refine its approach.

NYISO Model – Eligible Services

- **Energy Service:** dispatch-only model (no unit commitment), fully dispatchable continuous bid curve including withdrawal range if the aggregation has at least one "Withdrawal Eligible Generator".
- **Ancillary Services:** Operating Reserve and Regulation only; DERs not eligible for Voltage Support Service
  - "An Aggregation may only qualify to offer the Ancillary Services that all individual facilities in the Aggregation are qualified to provide". NYISO states that this requirement ensures compliance with NERC, NPCC, and NY state Reliability Committee rules.
    - For Regulation and Spinning Reserves (both 10-min and 30-min reserves): Generating units must use inverter-based energy storage technology; if DR is using local generator, it must use inverter-based energy storage technology.
    - IPR aggregations are not eligible for Operating reserves. They are allowed to provide Regulation, in which case, they would not be compensated for overgeneration, and non-performance penalties for under-generation would apply.
- **Dual Participation:** Dual Participation is allowed, and NYISO plans to work with distribution utilities to identify allowed retail/wholesale service pairs
- **Locational requirements:** DERs need to be located behind a single transmission node. NYISO has identified a total of 115 transmission nodes. Several factors are considered including system topology, transmission congestion, Distribution Utility footprint, etc.

Withdrawal Eligible Generator: "Generator that is eligible to withdraw energy from the grid at a price for the purposes of recharging or refilling for later injection back into the grid." An example is an Energy Storage Resource. NERC: North American Electric Reliability Corporation, NPCC: Northeast Power Coordinating Council, NY: New York

ENMAX EV Fleet Electrification

- ENMAX, the municipal utility for Calgary, purchased two Class 6 medium-duty electric trucks for its fleet as part of a pilot project
- The pilot aims to gather information on vehicle performance in the field to better inform future fleet electrification
- The trucks entered service in April 2022 and ENMAX intends to run the study for a full year, ultimately sharing data from the study with peer utilities
- ENMAX has targeted to electrify 35% of its 348-vehicle fleet by 2025 and 100% by 2030
- Approximately half of the pilot's $2.1 million budget was provided by Emissions Reduction Alberta, which distributes provincial government funding for carbon reduction projects
- ENMAX claims that fleet electrification will reduce lifecycle costs by 50% and save 4,300 L of diesel per vehicle each year
- The trucks have a custom-built body on Navistar's eMV series chassis.

Related Regulatory and Policy Commentary

Federal Government Climate Policy

- Carbon pricing now well established in Canadian economy, rising from $50/tCO2e in 2022 to $170/tCO2e in 2030
- Federal electricity sector net-zero target by 2035, economy wide net-zero target by 2050
    - 2030 Emissions Reduction Plan includes Canada Green Building Strategy, Low Carbon Economy Fund, Incentives for Zero-Emissions Vehicles, Pan-Canadian Grid Council
    - Interim targets for zero emissions vehicles established
- Federal Clean Climate Plan and Canada Infrastructure Bank Growth Plan – approx. $25B investments, available funding for projects/initiatives
- 2022 Federal Budget includes
    - $600 million over seven years for the Smart Renewables and Electrification Pathways Program to support additional renewable electricity and grid modernization projects
    - Establishment of investment tax credit of up to 30%, focused on net-zero technologies, battery storage solutions, and clean hydrogen
- Funding programs of interest to Ontario LDCs, who may be eligible to access funding to support grid modernization
    - LDC customers will also be eligible to access funding to support electrification, energy efficiency retrofits, renewable energy, and green hydrogen

Provincial Government Climate Policy

- Electricity rates have been priority for the provincial government, with ongoing concerns with respect to GA costs and its allocation to customers
- Ford Government is embracing ESG to attract investment, adopting more climate-friendly polices
  - New programs and supports were announced to protect and modernize automotive sector
  - Recently published low-carbon hydrogen strategy
- Via Ministerial Directive to IESO, supporting climate-friendly procurements
  - Evaluate a moratorium on procurement of new gas-fired generation, including development of an achievable pathway to phase-out gas-fired generation and achieve a zero-emissions electricity system
  - Establishment of a Clean Energy Credit (CEC) registry and framework to provide electricity customers (e.g., corporations, etc.) with ability to voluntarily acquire CECs and meet environmental and sustainability goals; launch by January 2023
  - Regarding resource adequacy, while the Minister supports IESO's use of competitive procurement mechanisms, IESO will also contract with the Oneida Energy Storage Project (250 MW / 1,000 MWh) and establish a new program for re-contracting hydroelectric facilities
- Understand need to provide low-carbon electricity supply; and recognize importance of meeting Ontario's supply needs and implications forecasted supply shortfall

Ontario Hydrogen Strategy

- On April 7, 2022, the Government of Ontario released its Hydrogen Strategy, which is a report outlining how to accelerate the development of a low-carbon hydrogen economy, and position Ontario as a clean manufacturing hub with a focus on clean steel, EVs, and batteries. The strategy includes:
  - Atura Power's Niagara Falls Hydrogen Production pilot which uses electricity from Sir Adam Beck generation station
  - Identifying Hydrogen hub communities, which leverage existing electricity infrastructure
  - Developing a feasibility study with Bruce Power to explore hydrogen production using excess energy from the Bruce Nuclear Generating Station
  - Developing an interruptible electricity rate to support hydrogen production
  - Supporting hydrogen storage and grid integration pilot project
  - Supporting industry transition and adoption of hydrogen fuel, including financial support of industrial projects (e.g., ArcelorMittal Dofasco)
  - Supporting Hydrogen research in partnership with Natural Resources Canada (NRCan)
- In Power Advisory's view, hydrogen is likely to play an important role in the net-zero economy
  - Given Ontario's rapidly emerging capacity needs, it will be important to ensure that hydrogen production and use is efficiently coordinated with the electricity grid so as not to work cross-purposes with capacity constraints and system needs

Purpose of the Clean Electricity Standard ("CES")

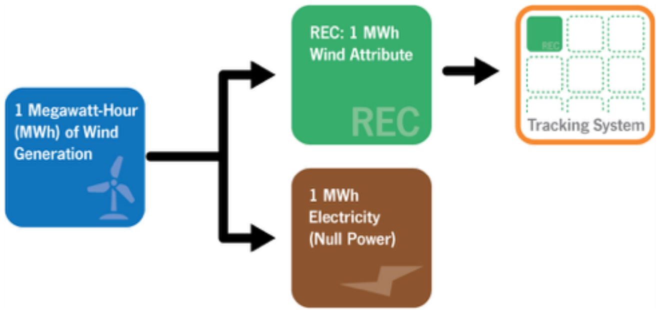
- In December 2020, the Government of Canada announced an economy-wide goal of net-zero emissions by 2050; electrification will play a key role in this transformation
- Having the electricity sector achieve net-zero by 2035 supports this economy-wide goal
- Government of Canada is taking action to reduce greenhouse gas ("GHG") emissions to reach a target of net-zero emissions for the electricity sector by 2035 ("NTZ2035")
- The Government of Canada recognizes that carbon pricing alone is not enough achieve the NTZ2035 goal
- The Government of Canada intends to send a clear regulatory signal to achieve NTZ2035
- It will enact a CES under the *Canadian Environmental Protection Act, 1999*
- The Government acknowledges that the provinces and territories, utilities, and generators will be the ones actually taking action to achieve NTZ2035
- The CES will need to harmonize its measures with the Output Based Pricing System ("OPBS") for large emitters

Proposed CES Regulations

- The CES will complement the already existing carbon pricing scheme in the OBPS to curb GHG emissions
    - The CES regulation will set emissions performance standards for GHG emitting electricity generators to ensure a transition to NTZ2035
    - The CES will be designed to ensure that there is an adequate supply of electricity to support increased electrification
- The Government of Canada recognizes the important role that natural gas plays in electricity sector; consequently, continued operation of natural gas-fired generation will be considered for special circumstances
    - The CES will be technology neutral, giving generators and utilities wide discretion in terms of supply options
    - The CES may include the use of GHG offsets and carbon removal technologies as a transitional measure to assist with compliance
    - The CES will recognize the significant regional differences that exist, i.e., certain regions depend more on fossil fueled generation and the impact of the CES will be larger in these regions
- The discussion paper indicates that wind and solar generation will play and important role in the NTZ2035 transition, and that measures will need to be taken to firm up these intermittent resources
- The discussion paper states that the Government of Canada is committed to ensure that workers affected by the NTZ2035 are not left behind and can be trained for new roles

Clean Energy Credits Registry

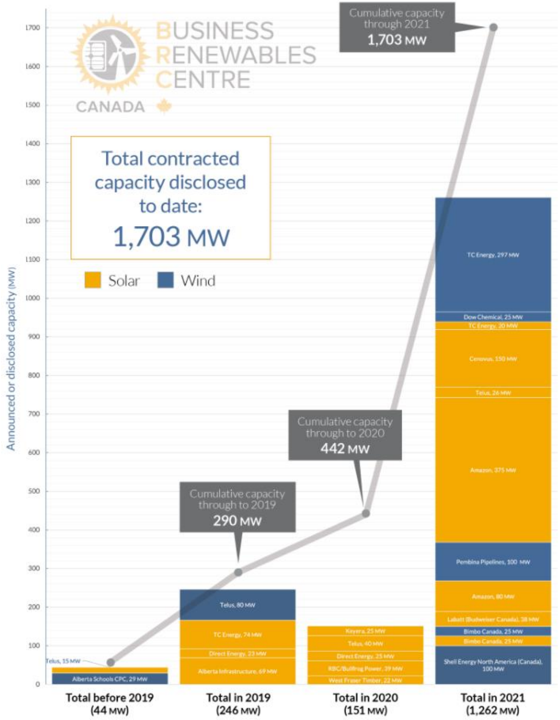
- On January 26, 2022, the provincial government announced plans to establish a voluntary CEC registry
  - CEC may include environmental attributes from all non-emitting resources including nuclear, hydro, wind, solar and biogas
- A voluntary CEC certificate represents 1 megawatt-hour (MWh) of clean electricity that has been generated from a non-emitting source
  - CECs are very similar to RECs in the US; they are not intended to meet any obligations, though, and are only purchased voluntarily



- IESO has been tasked with assessing options for the establishment and ongoing operation and management of a CEC registry
  - IESO is required to report back on or before July 4, 2022, with a view to launching the CEC registry in January 2023
- IESO currently holds all environmental attributes from contracted electricity resources; these attributes may be for sale in addition to new CECs that may be produced from new projects

Corporate Renewable PPAs

- Assisting corporations with achievement of their environmental, social and government (ESG) and sustainability goals is the ostensible reason for launching the CEC registry
  - The Minister of Energy, Todd Smith stated that "*The creation of a clean energy credit registry will give businesses the opportunity to meet their corporate environmental and sustainability goals when choosing to operate in Ontario and will also generate revenue which could be returned to Ontario ratepayers to help lower electricity costs.*"
- The transactions for corporate renewable Power Purchase Agreements (PPAs) in other jurisdictions are driven by two main reasons
  - Corporate ESG mandates and objectives, heavily driven by investors
  - Declining costs of renewable energy supply (i.e., wind and solar) and renewable energy enabling technologies (e.g., energy storage)
- Access to measured and verified environmental attributes can influence broader investment decisions by these companies which can have a positive impact on the Ontario economy and local communities



IESO Clean Energy Credits Report

- IESO has to report back to the Minister of Energy by July 4, 2022 on a proposed design for the registry, with a view to implementing the CEC registry in January 2023
    - Report has not been published publicly at the time of drafting this report
- Features under consideration:
    1. Web-based application accessible via a browser
    2. Allow for creation, certification, tracking, transfer and retirement of CECs for voluntary market
    3. Certification process for facilities should include location, capacity, facility name, facility owner, fuel source, commercial operation date
    4. All Ontario-based non-fossil fuel generation eligible to enroll and certify
    5. Each registered CEC will need certain attributes, e.g., location, date created, fuel source, third-party certification, etc.
    6. The registry needs to track the status, source, ownership and creation date for each CEC

Unbundled CEC From Existing Assets

- Ontario is forecasted to have ~130 TWh of clean supply per year for the foreseeable future
  - IESO has ownership of approximately 50% of the clean supply Environmental Attributes (EAs) produced, with most of the remaining owned by OPG
- Options to distribute EAs resulting from existing assets/generation are:
  - Free distribution
  - IESO direct sale to buyers
  - IESO release EAs to others for sale

CEC Option	Leads to Additionality	Bundle Product Available	Monetize Existing Investments	Residual Supply Mix Impact	Risks
1a: Unbundled CEC- Free Distribution	No	No	No	No	No mechanism to achieve 100% renewable/clean
1b: Unbundled CEC- IESO Sale	No	No	Yes	Yes	IESO conflict of interest; "greenwashing"
1c: Unbundled CEC- IESO Release EAs	No	No	Yes	No	Sale of EAs below purchase price; "greenwashing"

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Unbundled CECs From New or Re-Contracted Assets

- Over the coming years, IESO will administer a number of procurements to re-contract existing generation and procure new generation
- Under the Medium-Term RFP contract, IESO will not possess EAs of generation
- Possession of EAs for Long-term RFP is still to be determined
- EAs from these facilities could be available as unbundled credits

CEC Option	Leads to Additionality	Bundle Product Available	Monetize Existing Investments	Residual Supply Mix Impact	Risks
2: Unbundled CEC- MT-RFP, LT-RFP	Yes	No	No	Yes	None identified

Bundled CECs in a PPA (aka Corporate PPA)

- Stakeholders expressed an interest in direct Power Purchase Agreements (PPAs) between customers and generators
- CEC registry would serve as the tracking registry for creation and retirement of bundled CECs
- GA is an impediment to corporate PPAs in Ontario (i.e., companies can only hedge market prices, not GA)
- Bundled CECs could also be made available for sale in Green Pricing programs

CEC Option	Leads to Additionality	Bundle Product Available	Monetize Existing Investments	Residual Supply Mix Impact	Risks
3a: Power Purchase Agreement	Yes	Yes	No	No	GA allocation & potential ratepayer impacts
3b: Green Pricing Program	Yes	Yes	No	No	Program design and regulatory complexity

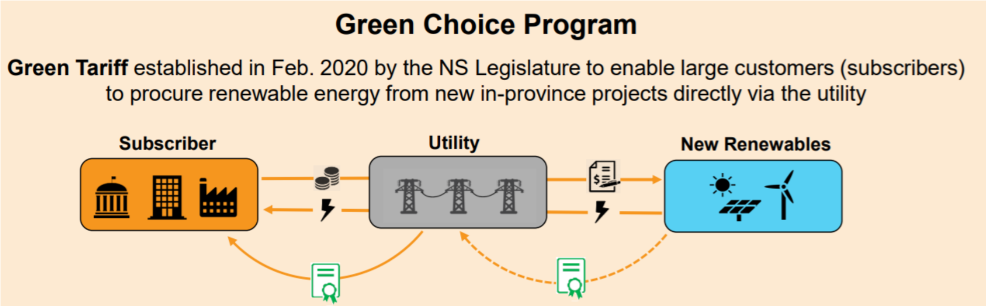
Commentary on Corporate PPAs

- Customers are increasingly interested in purchasing their own electricity supply with specific attributes or characteristics.
  - Ontario's statutory framework currently enables consumers to purchase electricity from generators or retailers; however, it is currently uneconomic for customers to purchase electricity from off-site generators given the GA
- If the current GA regulation remains, physical PPAs for behind-the-meter electricity supply will continue to be economic for customers, particularly Class B customers
- Removing barriers for corporate PPAs ultimately requires changes to the GA cost allocation framework
  - It could be argued that given the economic benefit associated with corporate PPAs and the fact that procured generation may reduce the need for IESO procured generation that corporate buyers should not be charged GA or should only be charged a portion of GA
- Overall, Power Advisory believes there are advantages to further enabling corporate PPAs, including:
  - Ability for customers to secure their own supply that reflects their own preferences or corporate objectives
  - Securing needed resources with the desired attributes without impacting costs to non-participating customer
  - Ensuring Ontario can capitalize on economic growth associated with ESG investment, and retain a competitive advantage
  - Reduce the magnitude of the electricity supply procured by the IESO, therefore reducing GA costs over time

Commentary on Green Choice Programs

- Local Distribution Companies (LDCs) may also be well positioned to support the acquisition of supply to meet the needs or preferences of customers

- Green Choice programs (e.g., Utility Green Tariffs) offered in other jurisdictions may be a potential model for consideration. Green Choice programs are common across the US as well, with more than 36 programs approved or pending across 19 states.
  - See for example, U.S. Electricity markets: Utility Green Tariff Update: https://cebuyers.org/wp-content/uploads/2020/08/REBA_Utility_Green_Tariff_Update_July_2020.pdf
  - Nova Scotia Green Choice Program: https://novascotiagcp.com
  - Toronto Hydro Climate Action Plan: https://www.torontohydro.com/about-us/climate-action-plan



Source: Nova Scotia

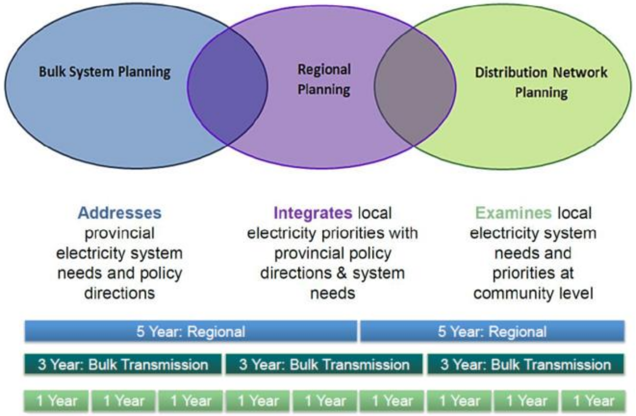
Evolving Power System Planning Processes

Evolving Reliability Standards

- Throughout 2020/2021, the IESO lead an engagement to review reliability standards and concluded to make some changes including adjustments to the resource adequacy for non-firm imports
    - While the scope of the engagement was narrow, many stakeholders raised broader questions with respect to resource adequacy framework in the future
- Traditional resource adequacy is derived from assessing loss of load expectations based on the probability of outages during peak demand hours; however, there is an increasing need to redefine reliability needs given the multitude of changes occurring in and to the electricity sector
    - Supply mixes are changing to include more variable renewable energy resources (e.g., solar & wind) and energy-limited resources (i.e., energy storage), both of which challenge the ability predict and dispatch energy production
    - Load flexibility and demand response capabilities are expanding which will change load shapes and create more volatility in real-time system operation
    - Extreme weather conditions and climate change trends will cause more challenges for system operations and restoration leading to required changes in system planning and design
- Overall, the IESO will need to continue to evolve reliability standards to meet these challenges and maintain power quality

IESO Regional Planning Process Review

- The IESO leads bulk & regional electricity system planning process; LDCs lead distribution network planning (see figure to right)
- On February 3, 2021, the IESO released the Regional Planning Process Review (RPPR) report that outlined three areas of focus for evolving the regional planning process
  - Improving the efficiency and flexibility of the regional planning process
  - Aligning transmission facility end-of-life (EOL) needs with regional planning needs
  - Addressing potential barriers to implementing non-wires alternatives (NWAs) in regional planning
- Within each area of focus the IESO identified multiple recommendations for implementation over the next few years; the IESO and OEB have collaborated to identify the organization responsible for review and implementation of each recommendation



- The OEB launched the Regional Planning Process Advisory Group (RPPAG) to assist in addressing the recommendations
  - Power Advisory was a member of the RPPAG

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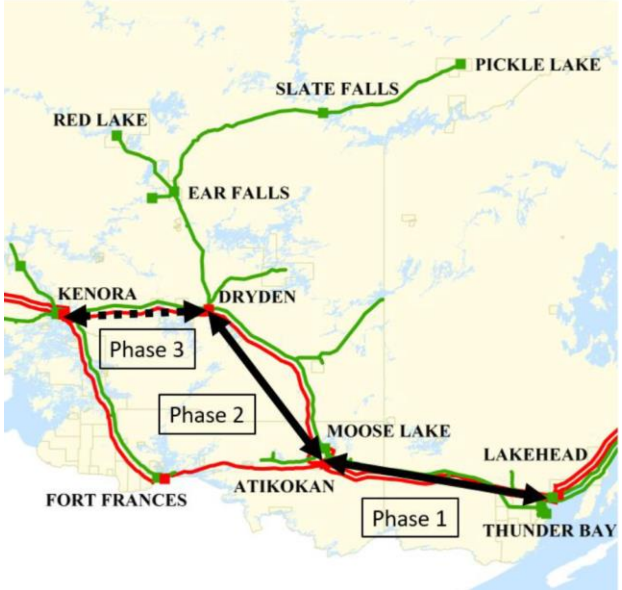
RPPAG Recommendations

- Throughout 2021, the RPPAG worked through the identified area from the IESO including:
  - Standardize & streamline load forecast development
  - Clarify scope of Integrated Regional Resource Plans (IRRPs) and Regional Infrastructure Plans
  - Better consideration of cost responsibility in regional planning processes
  - Better address end-of-life asset replacement in regional planning
- In addition, other recommendations were developed by the RPPAG
  - General education on regional planning process to stakeholders
  - Holistic coordination of planning processes – Regional, Bulk, Distribution, Natural Gas, and Municipal
  - Open stakeholder access to planning information/data
  - Existing option to bypass IRRP process
  - Potential changes to OEB's CDM guidelines to eliminate barriers
- Overall, the RPPAG initiated changes to the regulatory framework that will begin pivoting the direction and objectives of the electrical planning process in the province

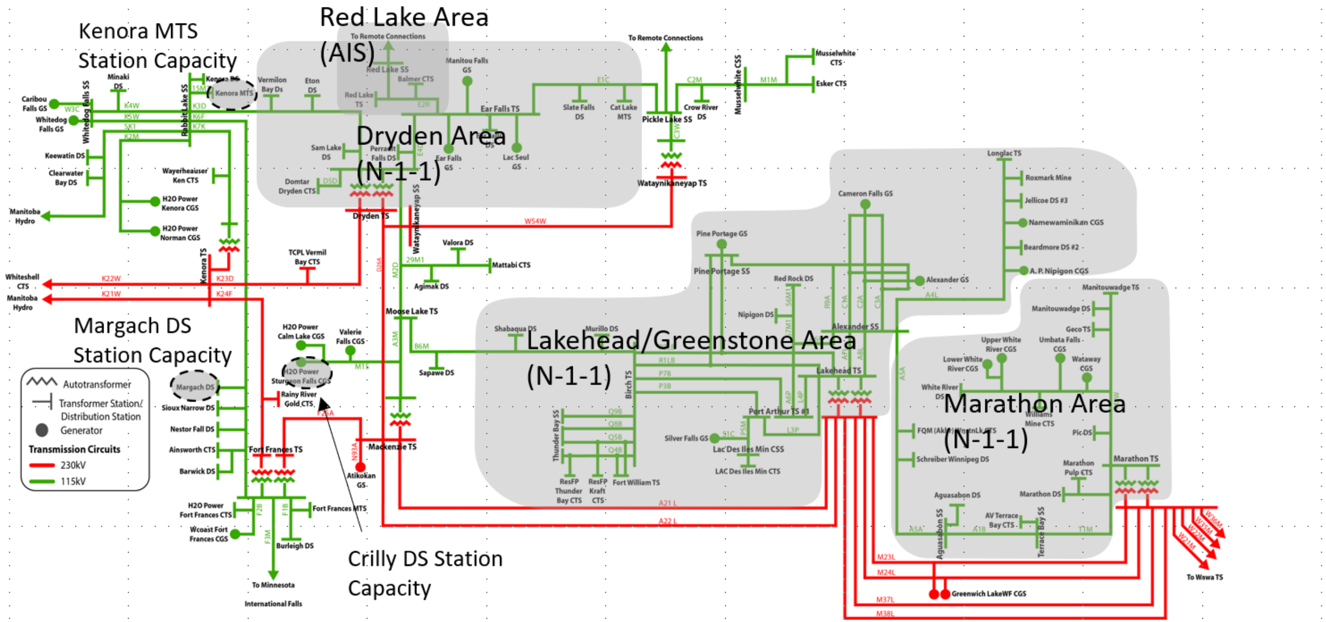
IRRP and Bulk Planning in Northwest Ontario

- There are a number of regional and bulk planning activities underway in Northwest Ontario
- Northwest Bulk Transmission Line – due to growing demand primarily from resource extraction, the IESO is proposing transmission expansion (i.e., Wassigan Transmission Line) in three phases starting in the next few years
- In addition to the bulk planning, a Scoping Assessment Outcome report for the northwest regions was published by the IESO
  - Scoping Assessment Outcome reports is the planning process prior to a fulsome IRRP
- The Scoping Assessment Outcome report for the Northwest identified a number of system needs over the next decade including Kenora MTS capacity expansion
  - SYNERGY NORTH has informed Power Advisory they are working with the IESO to explore NWS to address supply need; analysis later in this report will support these investigations



Wassigan Transmission Line Development Phases

Northwest Scoping Assessment Report Needs



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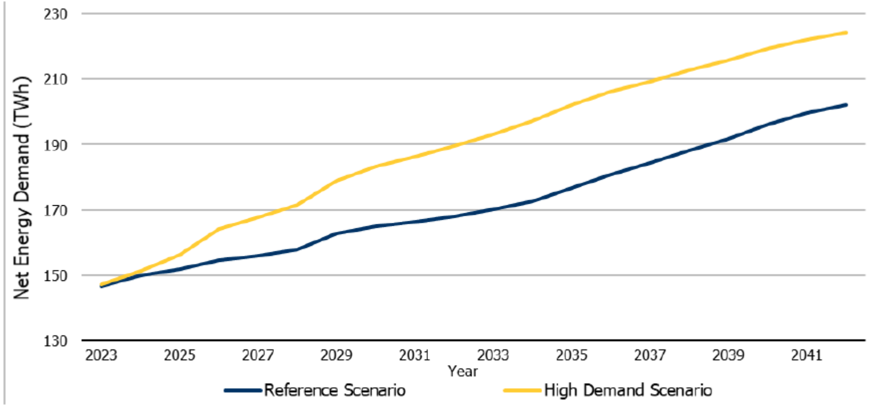
Electrification Assessment and Opportunity

Electrification Drives Demand Growth

- Electrification is the primary driver for demand growth over the next two decades as economic sectors seek options to reduce greenhouse gas emissions and take advantage of technology advances

- The pace of electrification will impact supply needs as well as upgrades and expansions of the transmission and distribution system
    - The IESO currently predicts that annual energy could be 20 TWh higher by 2030 under a high demand scenario (i.e., faster electrification and industry growth)

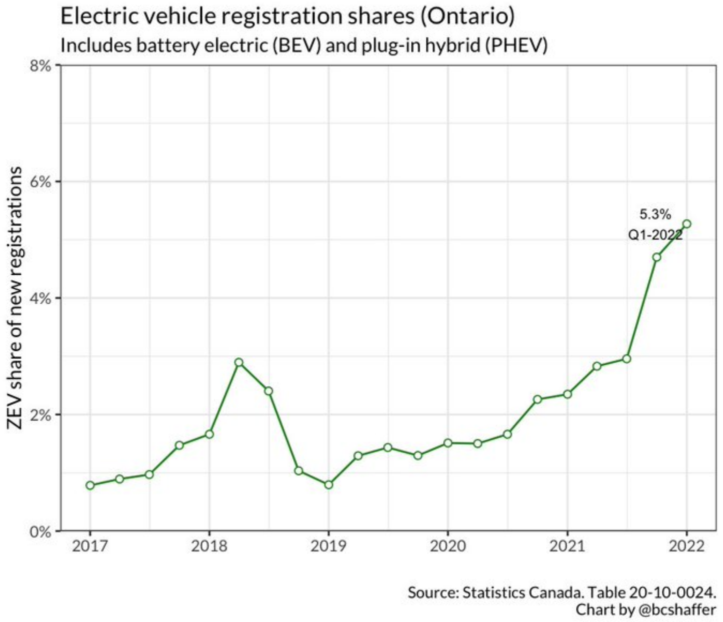


Transportation Electrification

- Electric Vehicles (EVs) are one of the most obvious electrification activities underway with almost all major automotive manufacturers planning mass production of EVs by the mid-2020s

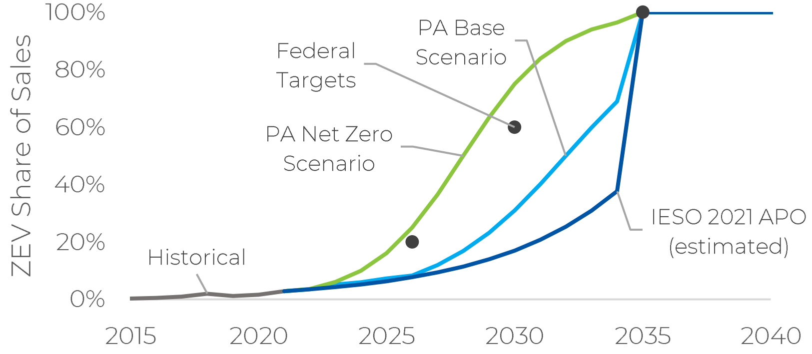
- Ontario is already starting to see the acceleration of electric vehicle adoption, reaching over 5% of new vehicle registrations in Q1 2022; Canada reached 7.7% for Q1 2022 led by Quebec and BC

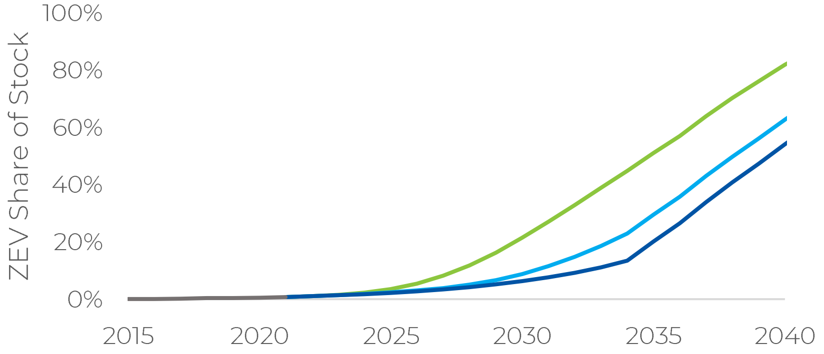
- High gasoline prices and government incentives are expected to support further acceleration of EV adoption across the province



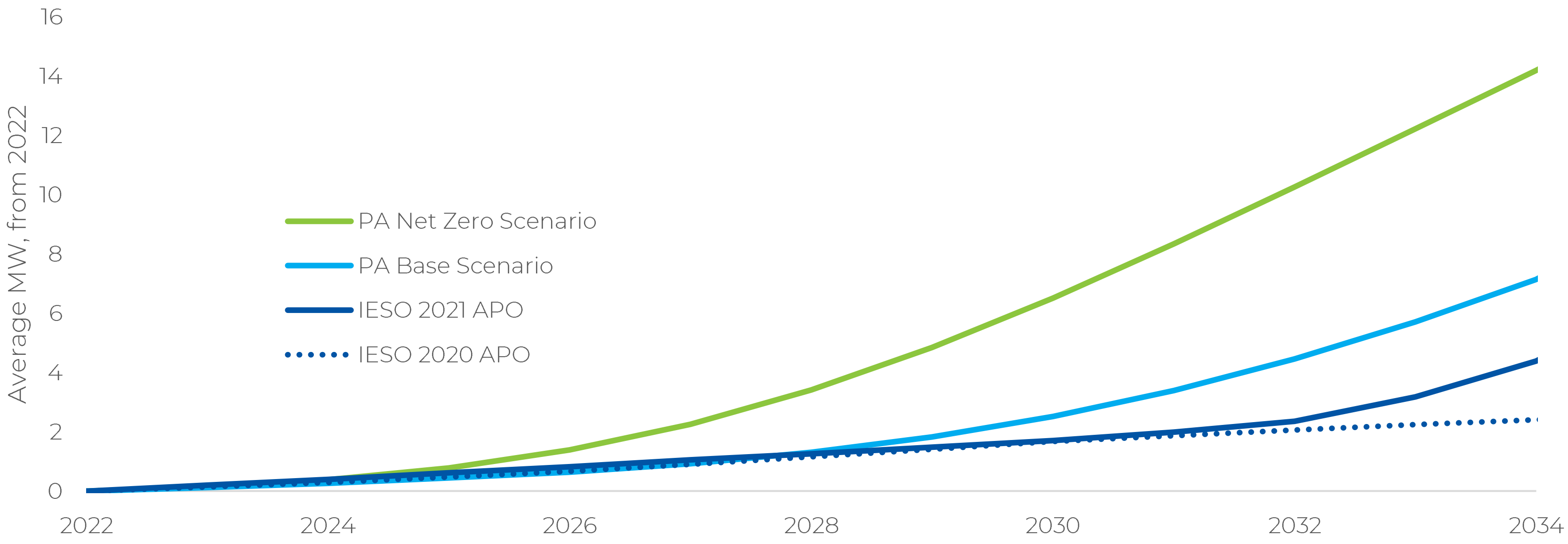
EV Forecasting Methodology and Assumptions

- Total light-duty vehicle stock (lower right) is forecasted based on government population projections. Total vehicle sales (upper right) are modelled assuming retirement and turnover after 15 years
- The federal government has targeted a 100% zero-emission vehicle (ZEV) sales share by 2035, with interim targets in 2026 and 2030
    - This leads to nearly 100% of light duty vehicle stock being ZEVs by 2050
- Power Advisory uses a higher EV forecast than the IESO's 2021 APO with a smoother growth in EV sales



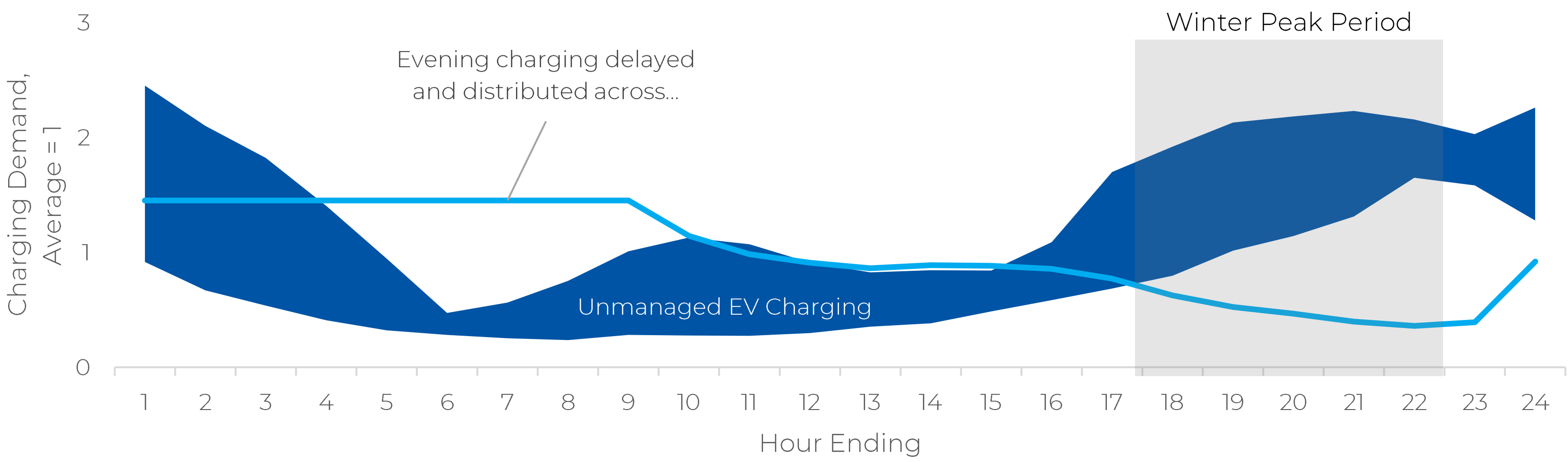


Average EV Load Growth for SYNERGY NORTH



- The EV forecasts on the previous slide were translated into average MW and scaled according to the Government of Ontario population projections for SYNERGY NORTH's service area

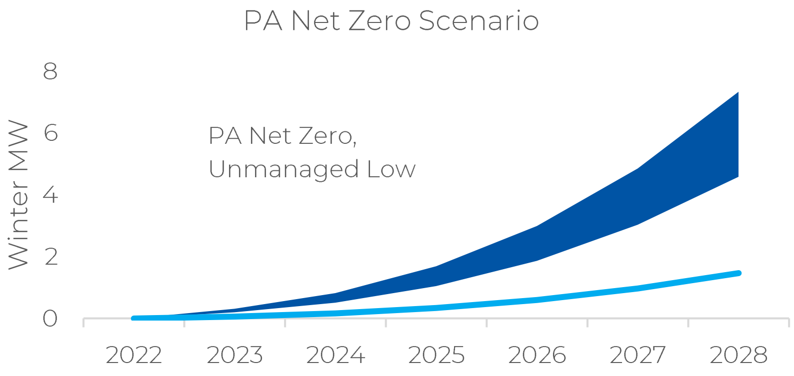
Peak Impact of Managed and Unmanaged EVs

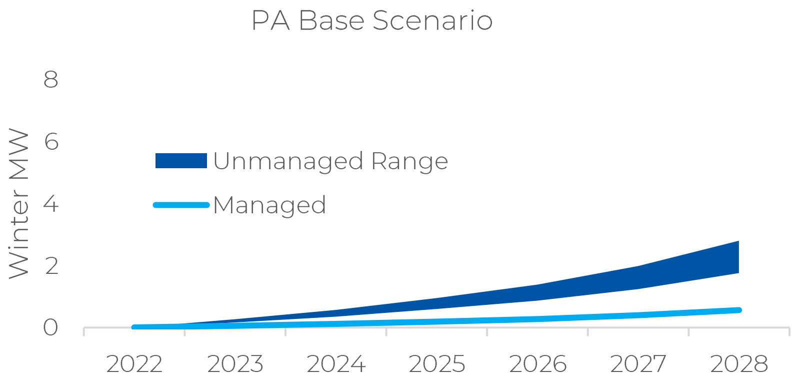


- The winter peak impact of EV charging can be over two times as much as the average demand
    - The range marked "Unmanaged EV Charging" is from several forecasts and empirical studies of residential charging patterns reviewed by Power Advisory
- The managed charging profile is a modified version of a profile used in the National Renewable Energy Laboratory's EVI-Pro Tool which assumes that charging is delayed to overnight when possible

EV Winter Peak Growth for Synergy North

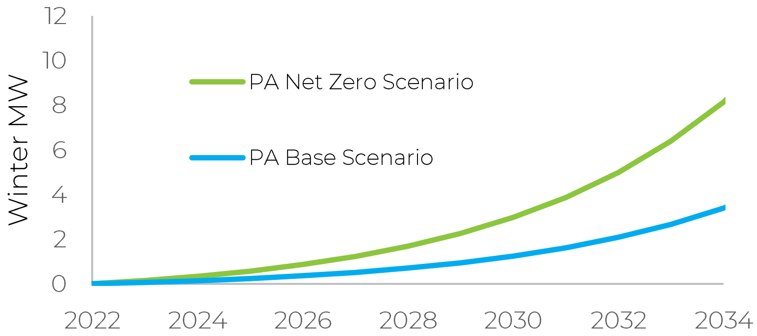
- The peak impact factors in the previous slide are applied to the forecast for average EV load to estimate winter peak impact and the peak savings that may be available with managed EV charging
- These represent best- and worst-case scenarios, across the range of assumptions for EV growth rate and level of control over the timing of EV charging





Space Heating Winter Peak Forecast

- Hybrid air-source heat pumps (ASHPs) are considered the most likely electrification option for residential heating in order to avoid unmanageable winter peaks on the power system
  - These devices operate at an efficiency of about 2.3 in mild temperatures and rely on a backup natural gas system below approximately -10 Celsius
- Space heating growth more uncertain than EV growth
  - Space heating electrification is not expected to become cost-effective for most consumers without further policy
  - Some buildings which currently use electric resistance heat could switch to heat pumps, leading to decreased demand
- Power Advisory's space heating electrification forecast is shown to the right
  - The Ontario total is adjusted for the Thunder Bay climate, scaled to Thunder Bay and Kenora population, and converted to winter peak megawatts assuming gas cut-in at -10 Celsius



Duel-Fuel Application by Hydro-Quebec & Energir

- Partially in response to the Quebec government's 2030 Plan for a Green Economy, Energir and Hydro-Quebec jointly filed an application to the Regie De L'Energie (Regie) on September 2021 to support the decarbonization of building heating through a Duel Energy Offer
  - The government objective is a 50% reduction of GHG emissions related to heating residential, commercial and institutional buildings
  - The Duel Energy Offer application requested to invest in converting natural gas heating to duel energy equipment
- The application requested the Regie to recognize the general principle that the method and contributions for reduction of GHGs must be considered for the purposes of establishing the revenue requirements of Hydro-Quebec in setting of its electricity rates and for the purpose of establishing Energir's required revenue under its tariffs
  - The application was for Phase 1 focused on residential customers with the intent of submitting to the Regie in the near future a second phase focused on commercial and institutional customers
  - Hydro-Quebec rate would need to increase to pay Energir for the lost revenue from reduced natural gas consumption

Conversion Scenarios

		All-to-Electricity Scenario			Duel Energy Offer		
		2025	2030	Total Potential	2025	2030	Total Potential
Energy	GWh	1314	2957	4929	817	1837	3062
Power	MW	920	2070	3449	28	63	105
GHG Avoided	Mt CO2e	0.34	0.75	1.25	0.24	0.54	0.89

	Energir Lost Revenue					
	All-to-Electricity Scenario		Duel Energy Offer		Difference (Duel Energy less All-to-Electricity	
$M	2025	2030	2025	2030	2025	2030
Revenue	-103	-255	-67	-167	35	88
Costs	-55	-136	-25	-61	30	75
Total	-48	-119	-43	-106	5	13

- In the application, Hydro-Quebec and Energir considered two scenarios: All-to-Electricity scenario & the Duel Energy Offer
- The Duel Energy Offer has less financial impact on Energir's revenue and achieves ~66% of the GHG emissions reductions of All-to-Electricity
- The Duel Energy strategy recognizes the limitations of 100% electrification for building heating that would create extreme winter system peaks on the electricity grid
  - Under All-to-Electricity, peak demand for Hydro-Quebec would increase by 3,500 MW, compared to 105 MW under the Duel Energy Offer
- Lower peak demand requirements avoids large supply need build out and significantly lowers the cost of service for all rate-payers

Opportunities for Energy Storage Deployment

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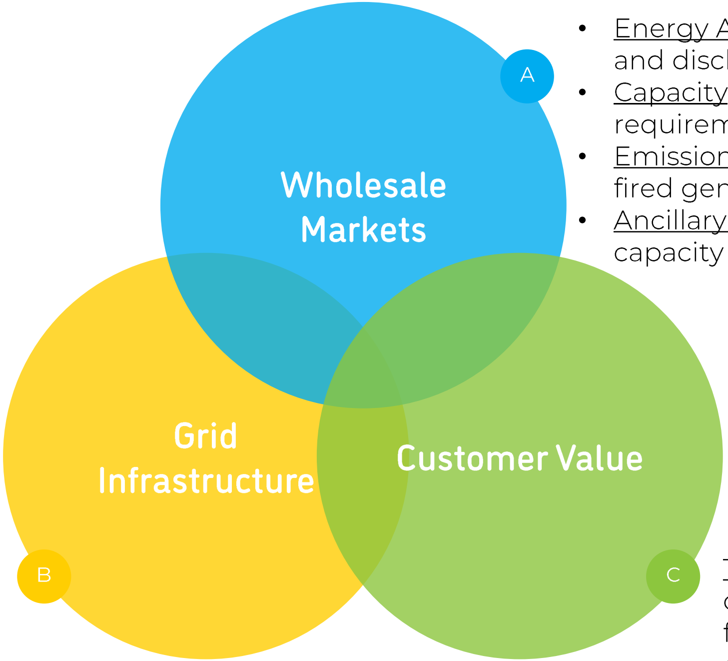
Energy Storage in Ontario

- The capabilities of energy storage resources are well documented in academic and empirical studies from jurisdictions around the world
- Ontario has for decades utilized its Pumped Generating Station (PGS) at Ontario Power Generation's (OPG) hydroelectric facility on the Niagara River to shift energy output from low to high-value hours
- Until recently, most energy storage projects were transmission-connected and undertaken in coordination with the province's system operator, the IESO
- Energy storage can be a cost-effective resource to smooth demand, mitigate the reliance on "peaking" plants typically powered by natural gas, and reduce overall system costs by avoiding the need for new capacity by better utilizing existing capacity
    - It can also help to reduce greenhouse gas emissions by shifting surplus energy from intermittent resources to high demand hours
- For grid infrastructure (i.e., distribution and transmission networks), energy storage can be used to defer or avoid new capital investments as well as enhance reliability and resilience (i.e., ability to manage low probability, high impact events)

SYNERGY NORTH Energy Storage Potential

- SYNERGY NORTH has two different energy storage development opportunities to address distribution system issues
- Deferment or avoidance of Kenora MTS station expansion
    - Kenora MTS station capacity is expected to reach thermal capacity limitations near end of 2020s; the load growth is moderate and amount of capacity required is manageable by a mid-sized (e.g., <10 MW) energy storage resource
    - An energy storage resource located at Kenora MTS can reduce thermal overloading (i.e., reliability services) and potentially pursue additional revenue streams (e.g., real-time energy arbitrage) to reduce the cost of reliability services needed
- Enhancement of reliability for customers located at end of radial lines
    - Distribution customers located at the end of long radial circuits can experience higher frequency and duration of outages due to the lack of alternative supply options (i.e., highly cost prohibitive to construct a second distribution circuit to the customer to improve reliability)
    - Behind-the-meter (BTM) energy storage located at the customer can enhance reliability through avoidance of momentary outages and short-duration (i.e., between 10 minutes to 2 hour) outages
    - Similar to large energy storage resources, the BTM energy storage can lower the cost of reliability service through the pursuit of additional revenue streams for direct customer basis

Energy Storage Value Propositions

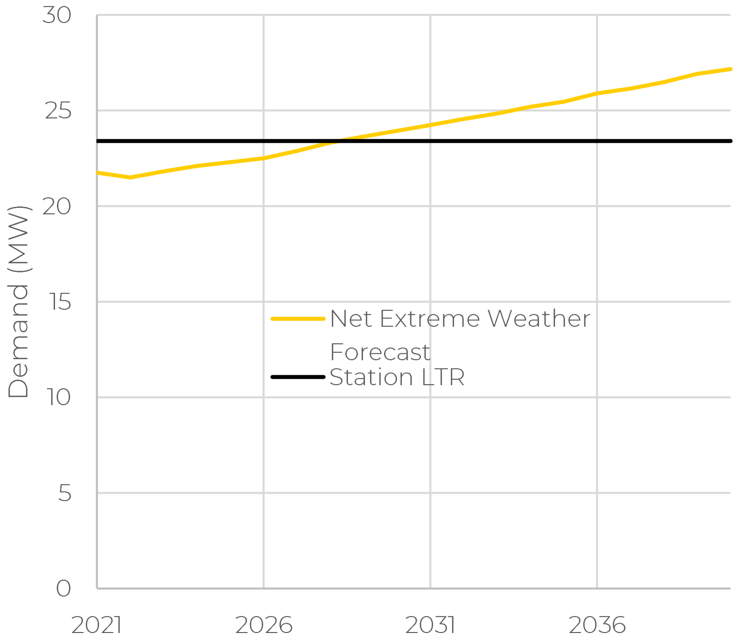


- Energy Arbitrage: Charging during low-cost hours and discharging during peak demand hours
- Capacity: Supporting resource adequacy requirements
- Emissions Reduction: Reducing the use of gas-fired generation
- Ancillary Services: Operating reserve & regulation capacity

Capital Deferral: Deferment or avoidance of new capital expenditures
Reliability Enhancement: Providing support during outage events
Resiliency Support: Utilized for system repair following major outages

Time of Use Shifting: Arbitrage between on-peak and off-peak pricing periods for Regulated Price Plan (RPP) customers
Outage Management: Maintaining minimum load during outage events (e.g., heating, cooking, lights)

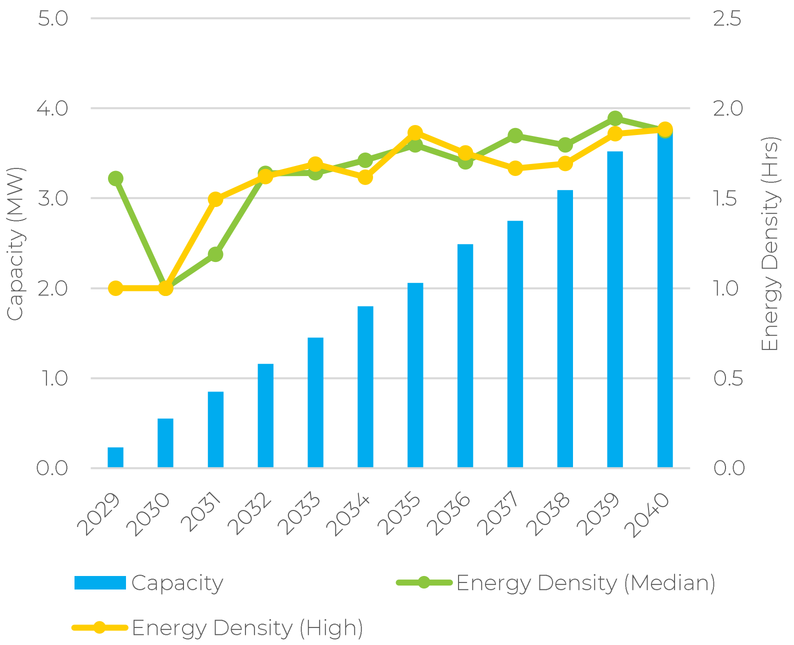
Kenora MTS Need and NWS Option



- Through the analysis for the Northwest IRRP, the IESO & SYNERGY NORTH forecast that Kenora MTS will reach capacity around 2029
- The IESO and SYNERGY NORTH are exploring non-wires options to address the capacity need
- A primary non-wires option would be to install energy storage resources at Kenora MTS to reduce loading during peak demand hours under the station LTR

Attributes to Determine Non-Wires Options Deferment Potential

- Energy storage resources are energy limited resources that have finite capability to discharge
- To determine the appropriate capacity and energy density of an energy storage resource, hourly load shapes are required
    - The IESO and SYNERGY NORTH developed multiple load shapes for future years to determine potential non-wires solution maximum discharge capacity and the energy density (i.e., duration of max capacity output) to avoid overloading Kenora MTS
- Power Advisory calculated the maximum output capacity and energy density required and concluded a 4 MW / 8 MWh energy storage resource should be capable of eliminate the overloading at Kenora MTS until at least 2040



Reliability Service Agreement for Non-Wires Solution

- An energy storage resource providing reliability service to a delivery network (e.g., distribution or transmission system) should be appropriately compensated for the service

- An approach to determine appropriate compensation would be to calculated the avoided annual cost to customers of deferring the capital expenditure
    - For example, a new substation would be charged to customers on an annual basis by amortization payments through the rate-base increase

- The avoided cost of amortization payments for a new asset could be used to determine a payment to the non-wires solution (e.g., energy storage resource) in exchange for providing reliability service

- A reliability service agreement could be used to detail the non-wires solution expected services
    - For example, ensuring the ability to reduce loading on an existing substation for a fixed number of hours a day (e.g., 4 hours) for a term (e.g., 10 years)

- The reliability service agreement would also be able to describe treatment of additional revenues from wholesale market participation and potentially provide pathways to evolve the non-wires solution should the system need change

Kenora MTS Reliability Service Payment Estimate

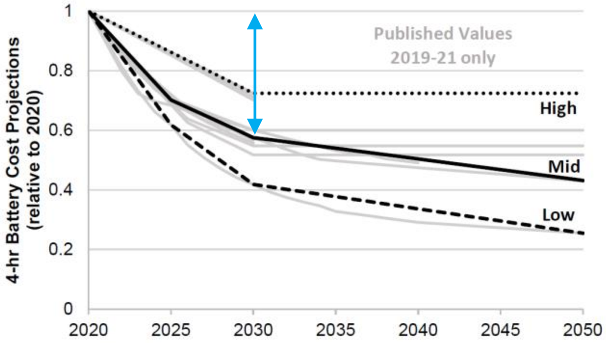
- The non-wires solution reliability service payment for Kenora MTS was determined based on the estimate cost of new substation at the existing voltage
  - o Power Advisory relied upon MISO's Transmission Cost Estimation 2022 for new and upgraded substation costs
- The table below details the assumptions used to estimate the reliability service payment under a high and low scenario
- Based on Power Advisory's analysis, a reliability payment based on 95% of the avoided cost estimate would range from $410,000 to $930,000 a year

Reliability Service Payment Estimate	High	Low
Utility Financing Assumptions		
Equity Return	9%	
Debt Rate	8%	
Debt/Equity Ratio	60/40	
Weighted Cost of Capital	8.4%	
Operating Life	40 years	
Overnight Capital Cost (CAD 2029)	$11,200,000	$5,000,000
Amortization Estimate	$431,000 / year	$980,000 / year
Avoided Cost Payment (95% of Amortization)	**$410,000 / year**	**$931,000 / year**

Energy Storage Cost Estimate

- Power Advisory utilized Lazard's levelized cost of storage to estimate the cost of a 4 MW/8 MWh storage facility based on a standalone Commercial & Industrial design (1 MW / 2 MWh battery x 4)

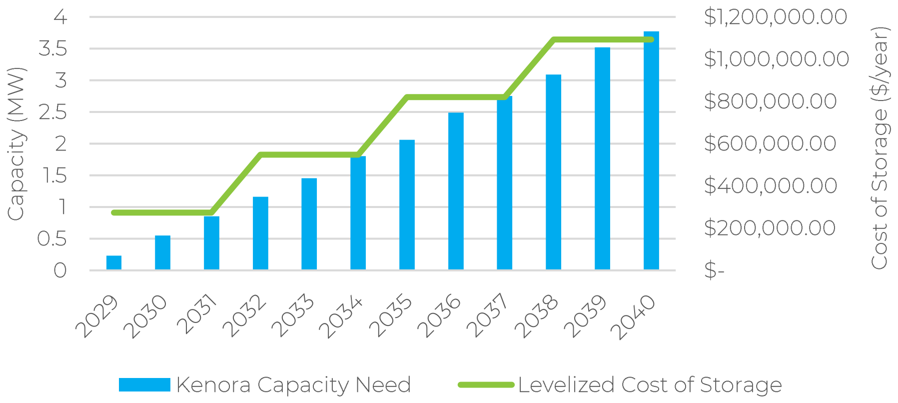
- Cost declines were based on the NREL 2021 update that expects energy storage costs to decrease by 40% from 2020 to 2030



Phased Installation of Energy Storage

- A benefit of energy storage resources is that the capacity can be added in phases to align with the system need, therefore better aligning spending with system needs
    - This is the reverse of traditional wires investments that require a rigid upfront capital investment that provides a large step change in capacity that might be under utilized in the future if demand outlook does not materialize as forecasted

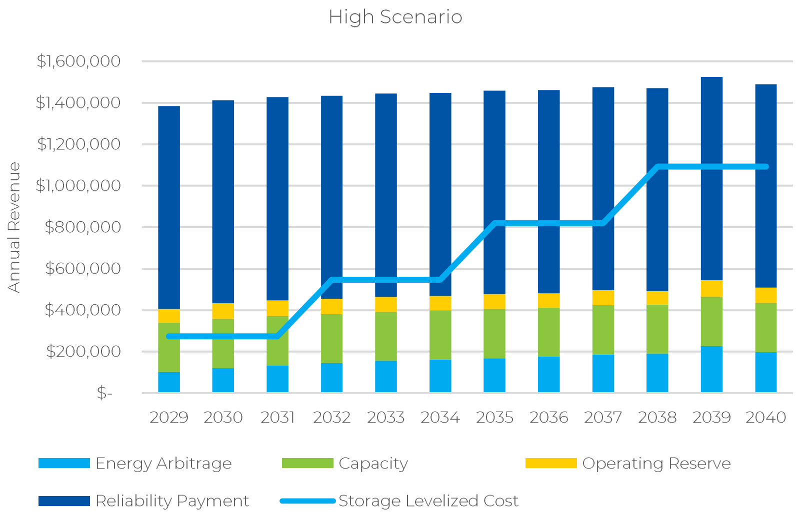
- Power Advisory's estimate of levelized cost of storage aligned with the capacity needs at Kenora MTS is shown below; by 2040, Power Advisory estimates the total levelized cost of storage to be ~$1 million/year

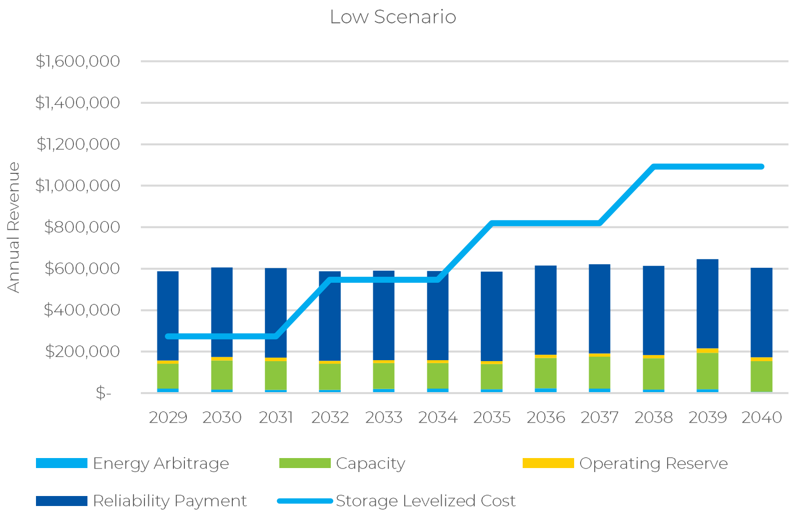


Energy Storage Revenue Potential

- Power Advisory developed a high and low revenue scenario based on the estimated reliability service payment and assumptions of revenue from wholesale market participation
    - Real-time energy arbitrage – charging in low priced hours and discharging in high priced hours
    - Capacity – offering capacity for Ontario resource adequacy needs, either through the Capacity Auction or under a long-term contract with the IESO
    - Operating Reserve – offering standby energy whenever fully charged and not expected to discharge for either reliability service agreement obligations or capacity obligations

Kenora MTS Non-Wires Solution Potential





- Based on Power Advisory's high-level estimate of revenue of a non-wires solution from reliability service agreement and wholesale market participation there is potential for the non-wires solution be a viable option for SYNERGY NORTH to pursue
  - Key next steps is confirm estimates of avoided cost and amending energy storage levelized cost with future cost reduction

Behind-the-Meter Energy Storage

- Energy storage is increasingly moving “behind-the-meter” (BTM) with small-scale battery storage projects

- As such, there is a growing demand and willingness by small consumers – including both households and small businesses – to consider battery storage as a way to improve reliability, reduce their total bill and/or achieve environmental goals by pairing storage with a solar panel system

- While battery storage projects can provide customers direct benefits, a large-scale roll-out of BTM battery storage will also be able to directly provide system-wide benefits to electricity customers across the province

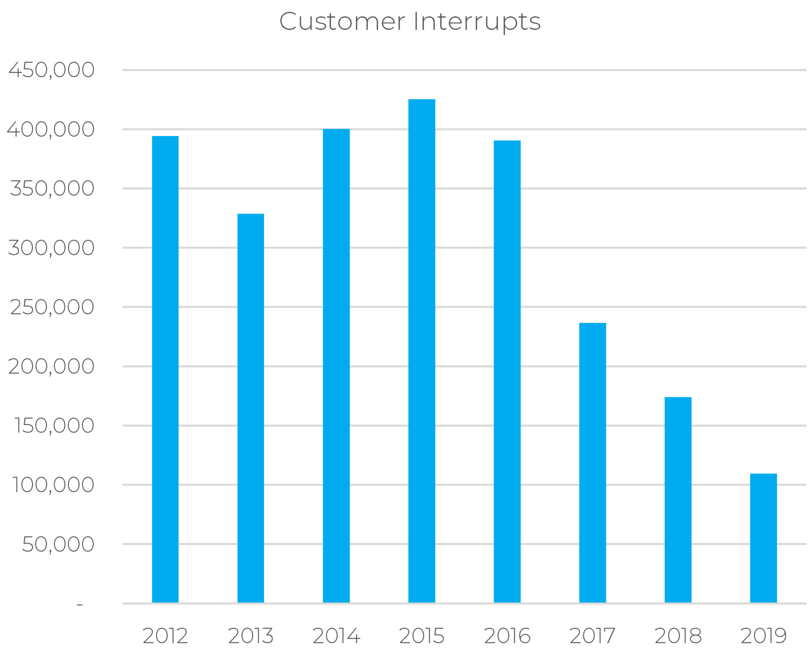
- Overall, small-scale battery storage projects can provide value in three areas:
    - IESO Wholesale Market Value
    - Utility Transmission and Distribution Infrastructure Value
    - Customer Value

Utility Transmission & Distribution Infrastructure Value: Reliability Benefits

- A report from Berkeley Lab (https://emp.lbl.gov/publications/updated-value-service-reliability) provides value of service reliability for electricity customers in the US, the results of the analysis are presented in the table below
  - While the analysis is provided for the US, Power Advisory views the analysis as an appropriate proxy for Ontario power system as a starting point for analysis

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

Avoided Customer Interrupts Value



- Reliability data provided by Synergy North indicates that customer interrupts have averaged ~300,000 over the time period of 2012 to 2019
    - Customer interrupts have improved significantly over that time period, the 3-year average for 2012-2014 was 375,000 customer interrupts while 2017-2019 was less than half at 175,000
- Based on the previous slide it could be inferred that the value of customer interrupts, assuming each interruption lasts on average an hour, is worth $1,567,000 per year for customers
    - This valuation assumes enough energy (e.g., 2 kWh) is retained by a small-scale storage facility for customer reliability purposes

Demonstration of Powerwall Reliability Benefits

- NRStor and MPOWER energy solutions launched the first home battery rental program to Toronto homeowners; allowing the participants to enhance their resiliency and support the grid during critical peaks

TORONTO'S FIRST VIRTUAL POWER PLANT (VPP) PILOT

BRINGING AFFORDABLE RESILIENCY TO THE DOWNTOWN CORE

THE OPPORTUNITY

We are launching the first major residential battery (Tesla Powerwall) rental program in Canada in one of Canada's most densely populated and electrically congested neighbourhoods. Our project will provide affordable resiliency to homeowners while delivering much-needed local and system-wide services to reduce electricity costs and emissions while avoiding costly substation upgrade infrastructure.

We want to support Toronto's ambitious sustainability targets through an equally ambitious VPP pilot project.

BENFITS OF ENERGY STORAGE

Homeowners

- **Increased Resiliency:** Onsite storage improves power quality and better protects essential systems.
- **Peak Energy Cost Reductions:** Optimizing local energy consumption based on TOU price signals reduces peak energy charges to customers.

Toronto Hydro & City of Toronto

- **Utility Benefits:** Toronto Hydro will be able to better manage peak demand and defer conventional infrastructure costs, while improving local power quality & resiliency.
- **TransformTO Goals:** This project directly supports the City's TransformTO storage and climate objectives.

Ontario's Independent Electricity System Operator

- **System Services:** Energy storage can deliver system services including DR, OR, etc.
- **DER Test Services:** The microgrid can deliver new IESO DER services including ramping, transactive energy, etc.

BENEFITS FOR TORONTO

COST-EFFECTIVE, QUICK DEPLOYMENT

The Tesla Powerwall is a rechargeable lithium-ion home battery that optimizes energy usage. Homeowners living in the service area (below) are eligible to rent a Tesla Powerwall for **$29.99/month**, plus a one-time connection charge of **$1,500**, representing a >50 lifecycle cost savings compared to a standard direct system purchase.

STRATEGIC SITING: ELIGIBLE ZONE

Energy storage can be strategically sited to deliver a combination of local and system-wide benefits.

Our project will aggregate a "fleet" of Tesla Powerwall units connected to the Cecil street substation to act as a decentralized battery. Customers located in the Spadina and College area of Toronto will be eligible to participate in this program (subject to additional pilot terms and conditions):

GOVERNMENT PRIORITY

"Our government is building an electricity system that works for the people,.. We are taking a comprehensive, pragmatic approach to building the modern, efficient, and transparent electricity system that the people of Ontario deserve".

– Hon. Rod Phillips, MoECP

ABOUT NRSTOR INC.

NRStor is an industry-leading energy storage project developer. We provide innovative solutions based on our unparalleled understanding of energy storage technologies, their costs, and the benefits they can provide.

We have earned our reputation as a leader in energy storage. NRStor built the first commercial flywheel storage project in Canada and is now building the first commercial fuel-free compressed air energy storage project in the world. We have over 100MW of lithium ion battery projects in development and a growing pipeline of exciting innovative projects.

A CONSORTIUM THAT CAN EXECUTE

- **NRStor:** Battery developer/owner, commercial ops. manager
- **MPOWER:** Canada's certified installer of the Tesla Powerwall
- **Enbridge Gas:** Utility integration and overall program growth
- **Toronto Hydro & City of Toronto:** Utility connection and integration
- **Tesla Energy:** Tesla Powerwall supplier and aggregation platform

TESLA POWERWALL FUNCTIONALITY

- Save on energy during on-peak hours
- Receive alerts in the event of a power outage
- Rely on a 12 to 24-hour backup power supply for your essential appliances and devices in your home
- Monitor your home energy use in real-time on your phone from anywhere

Control Your Energy from Anywhere

Seamlessly monitor and automatically manage your Powerwall, solar panels, Model S or X anytime, anywhere with the Tesla App.

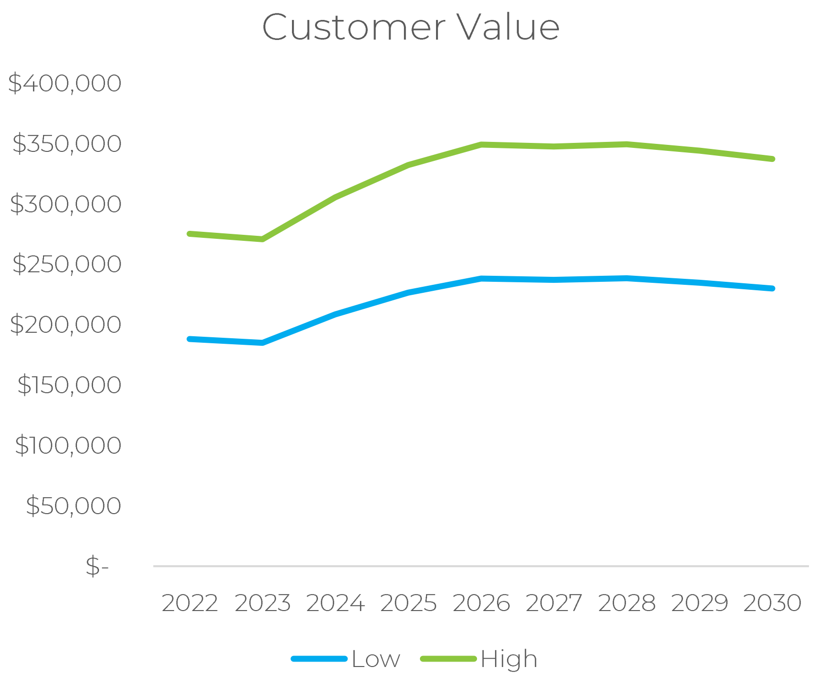
PROJECT PARTNERS

ENBRIDGE · MPOWER · TESLA ENERGY · TORONTO HYDRO · NRSTOR

POWER ADVISORY

Customer Value

- Most households in Ontario pay energy rates established under the OEB's TOU rate schedule, which is set twice a year for the winter/spring and summer/fall months
    - The TOU rate schedule includes an off-peak, mid-peak and peak rate based on different hours of the day that largely align with system-wide consumption patterns
    - TOU pricing is intended to encourage consumers to reduce consumption during peak demand hours and avoid the need (and cost) and of installing peak generating capacity
- Energy storage can mitigate the cost of TOU rates by charging during off-peak hours and discharging during peak demand hours
- Power Advisory modelled 5 kw/13.5 kWh battery system using current TOU rates and estimated the TOU savings for the deployment of 1,000 units at between $200,000/year to $400,000/year in customer value



Core Issues for Energy Storage Deployment by SYNERGY NORTH

Issue	Description
Merchant Risk from Energy Storage Operation	• Value stacking requires energy storage to pursue market activities in competitive environments • The pursuit of market service revenue is outside of the monopolistic objective of rate-regulated activities • Value stacking of energy storage services can inappropriately expose rate-payers to merchant risk)
Cost Recovery Treatment – capital or OM&A	• Simply put, distributors in Ontario are provided direct cost recovery for OM&A expenses (i.e., $1 spent in a year is recovered that year) and return-based cost recovery for capital expenses (i.e., $1 spent in a year provides a return on equity and total costs are recovered over an amortization period) • Distributors are incented to pursue capital investments through the approved return on equity • Typically, energy storage reliability services to distributors avoided capital investments that a distributor may receive a return on equity for traditional wires investments • There are some stakeholders in Ontario that have argued that contract payments for reliability service are OM&A expenses and should be recovered with no return; the obvious drawback of this approach is the utility is denied a return on equity and is therefore is no incented to pursuing the energy storage solution • This is a primary issue being considered by the OEB from the FEI working group recommendations and will influence investment decisions by utilities
Payment for Provincial Resource Adequacy Benefits	• In addition to reliability services, energy storage can offer capacity to the provincial system • Currently, the only option to access capacity payments from the IESO is through the Capacity Auction, a short commitment period (i.e., 6-month) annual process; this is not long enough to support capital investment of an energy storage resource • A longer term payment for global capacity is required; the IESO's procurement streams can help but the timing and alignment between reliability service agreement and procurement participation makes the option to participate in the IESO's long-term RFP practically impossible to pursue

Potential Solutions to Address Energy Storage Deployment Issues

- Contracting for reliability services with a third party that builds/owns/operates is a potential option to address merchant risk exposure
  - The reliability service agreement would prioritize reliability services to the utility but would allow the third party to pursue additional revenue streams to reduce the overall cost to the distributor
  - The contract terms and operations would influence the potential for additional services and the risk exposure of merchant activities to the utility
- Cost treatment for energy storage will require direction from the OEB
  - o SYNERGY NORTH could seek to put the energy storage asset and/or reliability service agreement payments into the rate-base with a variance account to capture costs until clarity of regulatory treatment is provided
- Direct engagement with the IESO through the IRPP process is likely the best option to determine a process for longer-term capacity funding for local energy storage projects
  - o The payment and service could be incorporated into the reliability service agreement
  - o There are many nuances that will need to be addressed through discussions with the IESO and other stakeholders (e.g., where will the funds come from, how will service quality be assessed, what is the objectives of the service, etc.)

Potential Energy Storage Deployment Process Steps – Kenora MTS

Step	Commentary	Timing
Estimate traditional wires cost	Determine the cost of expanding transmission station capacity to provide an estimate of reliability service payments to an energy storage resource	Immediate
Determine potential resource adequacy payments from IESO	Seek to understand options for IESO to provide funding stream for resource adequacy service from energy storage resource to meet provincial needs	Immediate
Assess physical constraints at station site	Determine if there is available land available to deploy an energy storage resource within or adjunct to the station stie	Next 1 to 2 years
RFI for energy storage costs and contract	Prepare an RFI to seek costs for energy storage resources as well as survey proponents on contract terms, provisions and options to maximize customer value	Following estimate of traditional wires costs and IESO resource adequacy payments
Monitor Hydro One JRAP energy storage outcomes	Outcome of Hydro One JRAP will provide guidance on treatment of energy storage resources deployed by rate-regulated utilities	End of 2022
Monitor OEB response to FEI guidance	The FEI guidance document may result in OEB generic proceedings, code amendments, or other regulatory changes that will influence the deployment of energy storage resources by rate-regulated utilities	Over next 1 to 2 years

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EV Opportunities Assessment

EV Charging Levels Overview

	Level 1	Level 2	Level 3 (DC Fast Charging)
Voltage and Power	120V/40A (standard wall outlet)	208/240V/40A (e.g. dryer plug)	240V or 480V AV, 24kW to 350kW (typically 50 kW for most vehicles)
Charge Time	8 to 12 hours, or more	4 to 8 hours	30 minutes to 80%
Equipment Cost (CAD/port)	None	$2,000 to $9,000	$25,000
Make Ready Cost (CAD/port)	None	$3,000 to $10,000	$9,000

- Costs are approximate; technology is evolving quickly and there is a wide range of estimates
- Residential Level 2 chargers are typically lower cost than public Level 2 chargers

EVs as Distribution Resources

- EVs have significant potential as distributed energy resources
- Vehicle-to-grid technology describes arrangements where EVs discharge energy to the system
- Different arrangements are possible, such as exposing EVs to real-time prices or allowing the distributor to have fine-grained control over their charging
  - Practical implementation of these projects to date has been very limited due to technological, economic, and regulatory barriers
- In the current environment, a reasonable first step is to treat EVs as potential demand response participants, in addition to flexible residential loads like air conditioners and water heaters
  - Aggregation schemes can increase effectiveness (i.e., ability to deliver electricity services) and lower costs
- Local Demand Response can help to manage growth on distribution networks without building new equipment
  - Eversource, a New England utility, offers customers with certain Wi-Fi enabled Level 2 chargers up to $300 for enrolling in a demand response program
  - The IESO has partnered with Toronto Hydro on a pilot project to demonstrate how distributors can procure and dispatch demand response for local/distribution-level needs in addition to wholesale market needs

Supporting Residential EV Charging

- The majority of overall charging is expected to occur overnight at home, particularly with the OEB's proposed Ultra-Low Overnight Price Plan (TOU rate of 2.5 cents/kWh)
- The substantial load growth anticipated from EVs over the next few years will likely require system upgrades
  - Passive load shifting from TOU rates and active load control through demand response and similar programs can only partially mitigate this growth
- SYNERGY NORTH should develop a stronger understanding of:
  1. Local EV uptake and forecasting in residential neighbourhoods – it is not enough to rely on the province-wide IESO forecast
  2. Excess capacity on the existing system, and areas with limited excess capacity that will need upgrades sooner
- In partnership with municipal governments, SYNERGY NORTH may have a role in enabling more public charging, particularly pole-mounted chargers for residences with on-street parking

Public Chargers Currently Installed

- The National Renewable Energy Laboratory (NREL) and Natural Resources Canada (NRCAN) compile and publish a dataset on public EV chargers in the US and Canada.
- Analysts frequently highlight a shortage of public chargers across Canada compared to what is needed for the current pace of EV adoption

Number of Ports	Level 1	Level 2	DC Fast Charger (Tesla)	DC Fast Charger (Other)
Thunder Bay	4	14	6	5
Kenora	7	1	6	1

- The OEB issued a bulletin in 2016 which clarified that "ownership or operation of an EV charging station … do not constitute distribution or retailing." The same bulletin suggested that distributors may own and operate EV charging stations if the equipment assists with load management.

Estimating the Need for EV Chargers

- Charger location
  - Home: Surveys suggest that as much as 80-90% of charging will happen at home; some reports anticipate home charging to make up as low as 60% of total charging with widespread public charger availability
  - Workplace: second most popular location and the best for public charging, with anticipated share of charging demand in the 15-35% range
  - Public: on-street and at destinations; typically less important in transportation studies
- Charger level
  - There is a wide range of estimates from different studies
  - Each charger covers fewer vehicles in the near term as the priority is building up a dependable network
  - A report commissioned by Natural Resources Canada projected the following ratios between EVs and public chargers

Table 1: Estimated EV to charger ratios for Canada.

	2020	2025	2030	2035	2040	2045	2050
EVs/Level 2	15	22	31	41	46	53	56
BEVs/DCFC	140	180	220	260	290	330	350
EVs/Port	14	20	27	36	41	46	49

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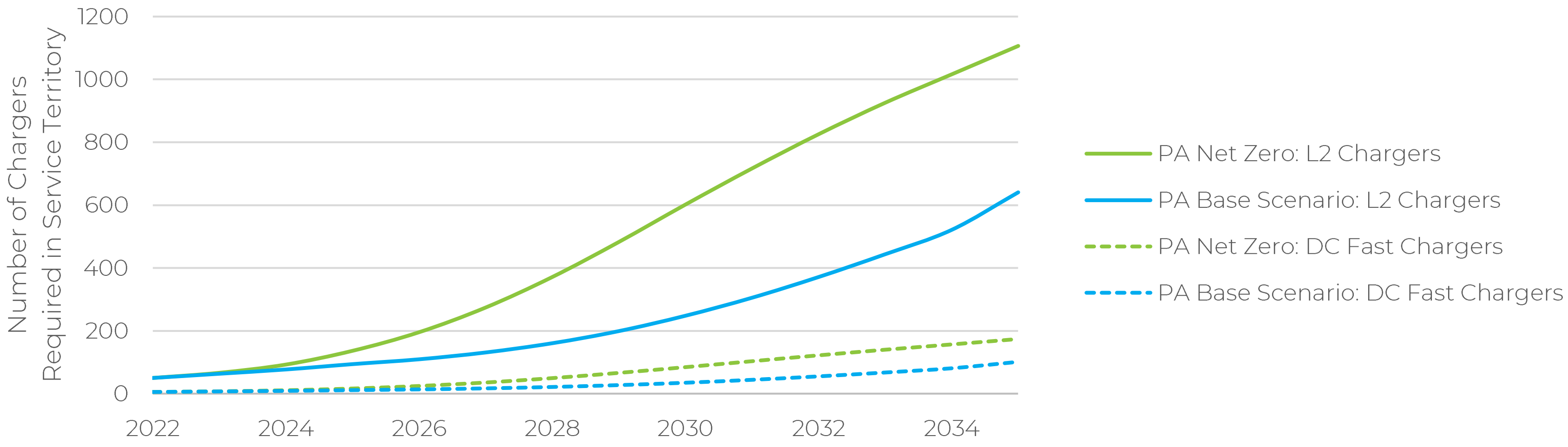
Projected Public Charger Demand



- A forecast of public charger demand is created by applying the EV/charger ratios in the previous slide to the two Power Advisory EV uptake forecasts for SYNERGY NORTH

- The analysis indicates that there is already a shortfall of Level 2 chargers

- The federal government has committed $680 million through 2027 to support electric and hydrogen fueling stations in public, workplace, and fleet contexts through the Zero Emission Vehicle Infrastructure Program (ZEVIP)

Case Studies: Utility/City-Owned Chargers

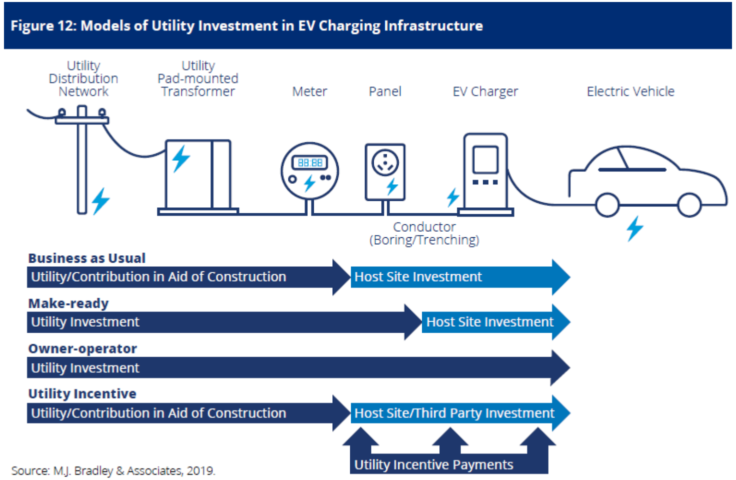
- Austin Energy
  - Rebates and assistance with installation of home Level 2 chargers; higher rebate for Wi-Fi enabled charger
  - Over 1,000 public Level 2 chargers in the city; unlimited access with a $4.17 per month subscription (launched in 2011)
  - 29 Level 3 chargers priced at $0.21 per minute (starting in 2020)
- Houston
  - Municipal fleet electrification; installed city-owned chargers at depots provided by ChargePoint, GRIDbot, and Blink with federal funding
- Seattle City Light
  - Residents who cannot access off-street charging (i.e. garage, driveway) at their home can request a public, pole-mounted Level 2 charger near their home
  - The charger are installed, owned, and operated by Seattle City Light and available for $0.20/kWh
  - Parking spots next to the chargers are designated for EV charging only
  - The utility is also building out a network of fast chargers inside the city, focusing on areas not well-served by private chargers

Case Study: Toronto Hydro On-Street Charging

- Toronto Hydro conducted a pilot program with the City of Toronto in late 2020 to install 17 Level 2 on-street chargers on 9 public streets, with financial support from the federal ZEVIP program
- The pilot was extended due to concerns that data collected in 2021 was not representative of long-term use
    - Utilization (i.e. share of time spent connected to a vehicle) increased as the study went on, reaching an average of 25% (range 0-57%) by April 2022
- Charging revenue was $28,529 and charging expenses (excluding administration and capital cost) were $23,666. Toronto Hydro intends to raise charging prices in order to recover more of the program costs
- The city has directed Toronto Hydro to install 32 more stations by the end of 2022. Based on pilot experience, Toronto Hydro estimates a per charger cost of $20,000
- Overall, the experience of Toronto Hydro and other utilities suggests that there is not yet a strong business case for public EV charging
    - Most large public charging networks to date tend to have significant support from the federal and municipal government

Case Studies: Make-Ready Ownership Model

- National Grid (Massachusetts)
    - Cost recovery for a 3-year pilot starting 2018 was allowed in accordance with a state law
    - EV make-ready approach: National Grid would prepare sites for charging and facilitate installation but would not own or operate the chargers themselves
    - National has also recently piloted 16 chargers owned by the City of Melrose but mounted on National Grid poles
- Georgia Power
    - Georgia Power will own and operate all charging infrastructure behind the customer meter all the way up to the charger
    - In the order approving the program, Georgia Public Service found that allowing the EV charging station costs and supporting infrastructure costs into rate base strikes the right balance between the monetary and non-monetary benefits associated with EV infrastructure deployment



EV Opportunities Next Steps

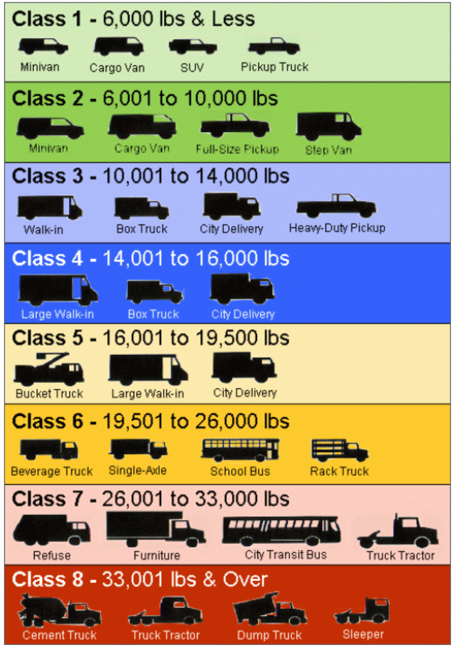
- Power Advisory proposes the following next steps to manage the growth of EV load

Immediate	• Forecasts: Develop and regularly update granular internal EV forecasts, focusing on residential neighbourhoods and vehicle fleet depots • Studies: Perform system studies to identify circuits that have room and plan network upgrades for those that don't; consider publishing information on areas with room for more public chargers • Process: Be prepared to work with public charging installers; develop streamlined processes
Options to Explore	• Municipal Partnerships: Determine how SYNERGY NORTH can support municipal climate policy, including facilitating municipally-owned chargers (e.g. pole-mounted EV chargers in neighbourhoods without garages and chargers at public buildings) • Demand Response: Local demand response pilot program, potentially tied to home charging incentives, or partnership with an established demand response aggregator
Potential Futures	• Make-Ready: Monitor regulatory developments and innovation on ownership models • Vehicle-to-Grid: Monitor technology and enabling policies

Fleet Electrification Assessment

Zero-Emissions Heavy Vehicles

- In economy-wide net zero plans, heavy vehicles are consistently highlighted as one of the more challenging categories to address
- The weight and cost of batteries can make electrification impractical for some vehicles and applications
  - Examples of vehicles ill-suited for full electrification include those with long range requirements, high utilization, towing/cargo-focused vehicles, or for emergency response vehicles
  - On the other hand, many fleet vehicles with predictable schedules will be more easily electrified (e.g., shuttle buses, delivery vans)
- A zero-emission utility fleet will likely comprise:
  - Battery electric for Class 1-4 vehicles and heavier vehicles which can be used in short bursts
  - Alternative fuels (hydrogen or renewable natural gas) for the heaviest vehicles
- Electric heavy vehicles are evolving quickly, with many major developments occurring in Summer 2022



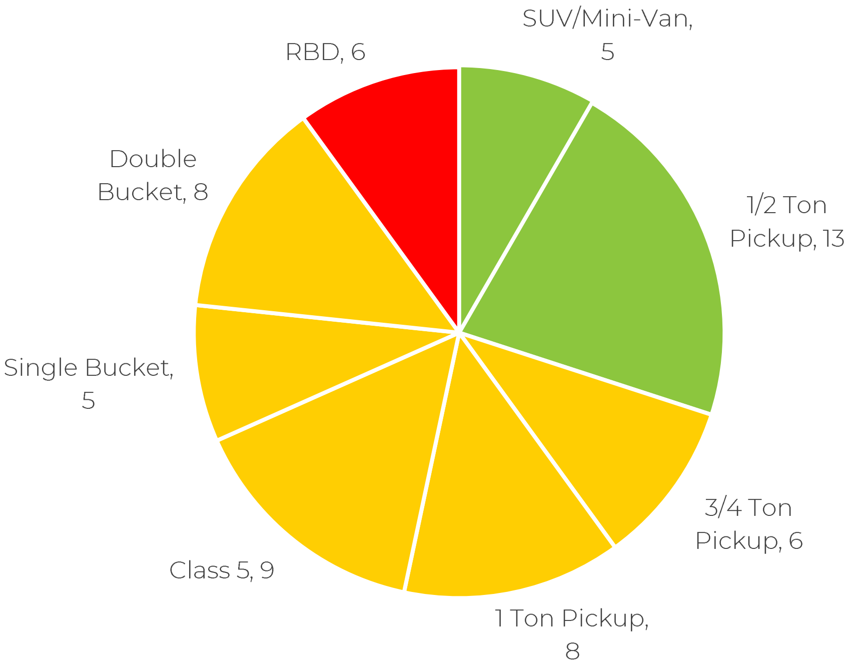
Gross Vehicle Weight Ratings, Source: U.S. Department of Energy

SYNERGY NORTH Fleet Electrification Options

Electrification Potential	Vehicle Type	Count	Comment
Current Technology	SUV/Mini-van	5	- Multiple options now on the market
Current Technology	Half-Ton Pickups	13	- Ford F-150 Lighting (launched April 2022) - General Motors, among others, is launching competitor models (both GMC and Chevrolet brands)
Emerging/Limited Applications	Three-Quarter- and One-Ton Pickups	14	- Ford has ruled out heavier models of the Lighting for now - General Motors has confirmed they are working on them, with no clear timeline beyond a 2035 goal to be all-electric - Magna has demonstrated a drop-in electric powertrain for heavy trucks which it is offering to automakers
Emerging/Limited Applications	General-purpose Class 5 Trucks	9	- Ford offers an E-450 platform (Class 4) which could be suitable for some applications - SoCalGas recently announced a demonstration project to develop a hydrogen fuel cell Ford F-550 for utility work
Emerging/Limited Applications	Bucket Trucks	13	- Terex announced an all-electric bucket truck in June 2022. Nine utilities, including SaskPower, have already committed to orders.
No Available Options	RBD	6	

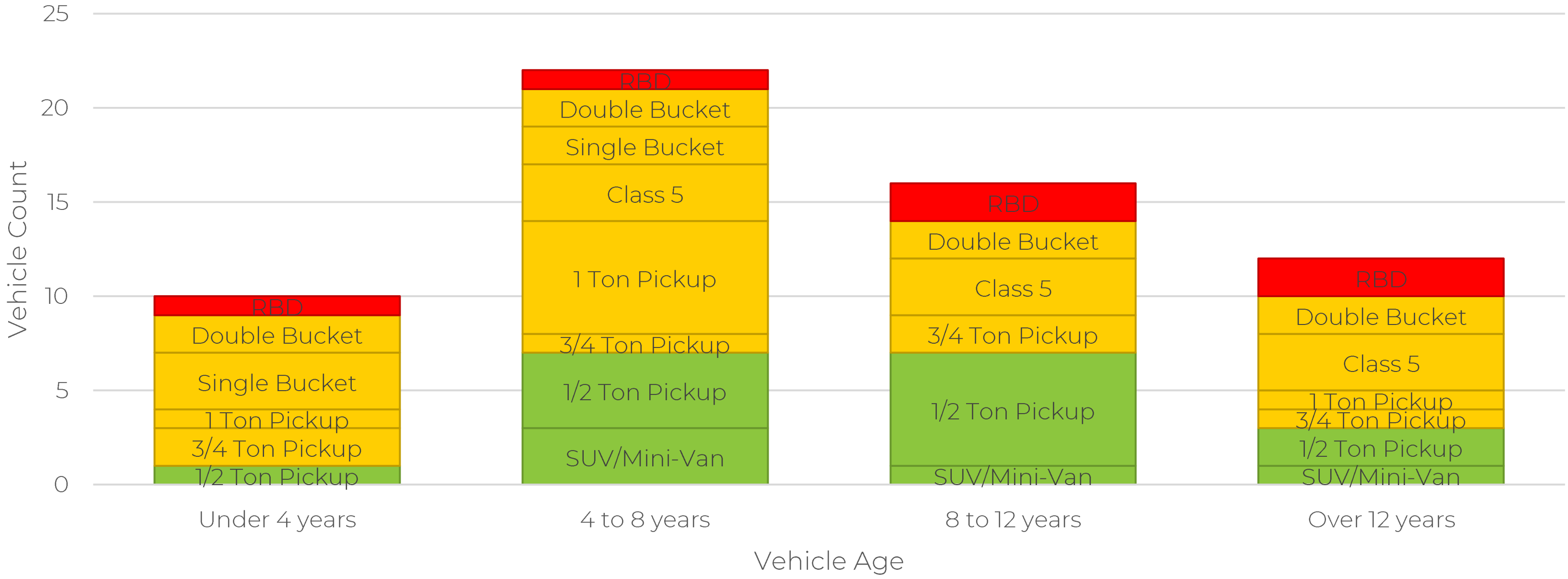
SYNERGY NORTH Fleet Overview (Totals)

- Lighter vehicles are cost-effective to electrify with current technology, provided the range and power available can meet SYNERGY NORTH's requirements
- For heavier trucks (3/4 Ton to Class 5), there may be opportunities to partially electrify in the mid- to late-2020s using current and emerging technology
    - Maximize electrification by identifying applications where a lighter truck suffices or with limited daily range requirement
- For specialized vehicles (bucket trucks and RBDs), continue to pressure manufacturers and monitor demonstration projects



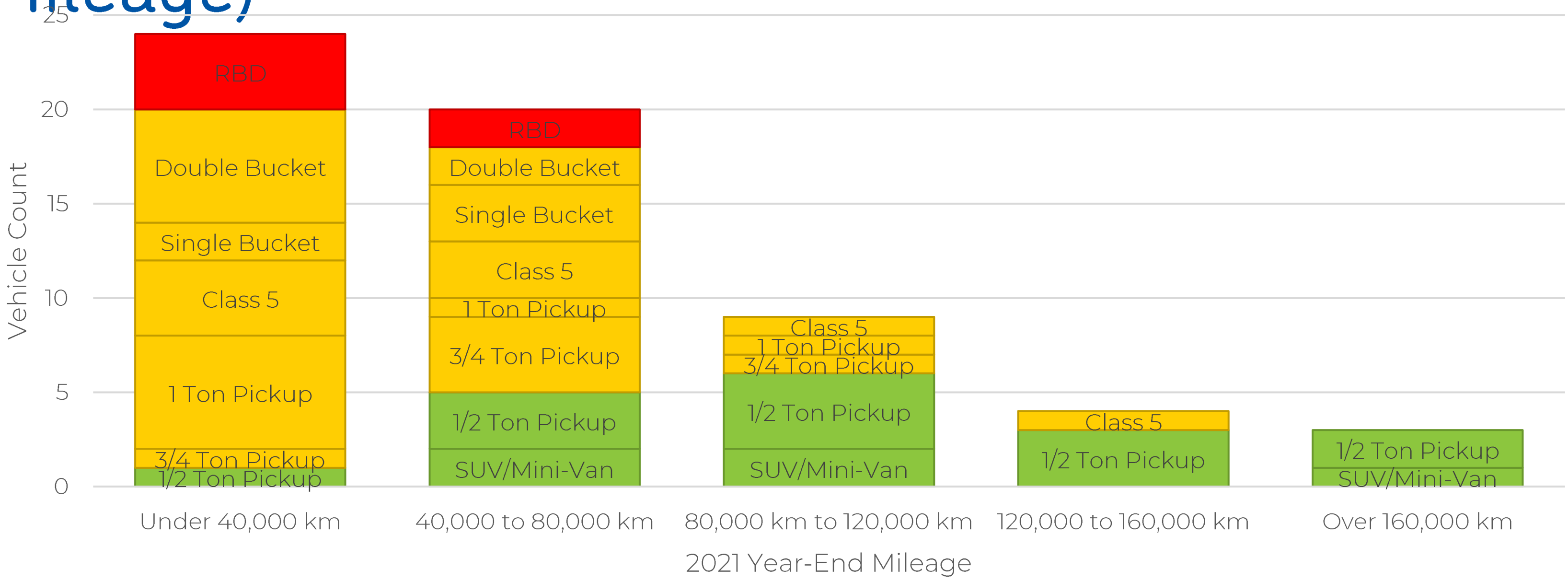
Unspecified pickups assumed to be half-ton, cube trucks assumed to be based Ford F-550 or similar

SYNERGY NORTH Fleet Overview (Age)



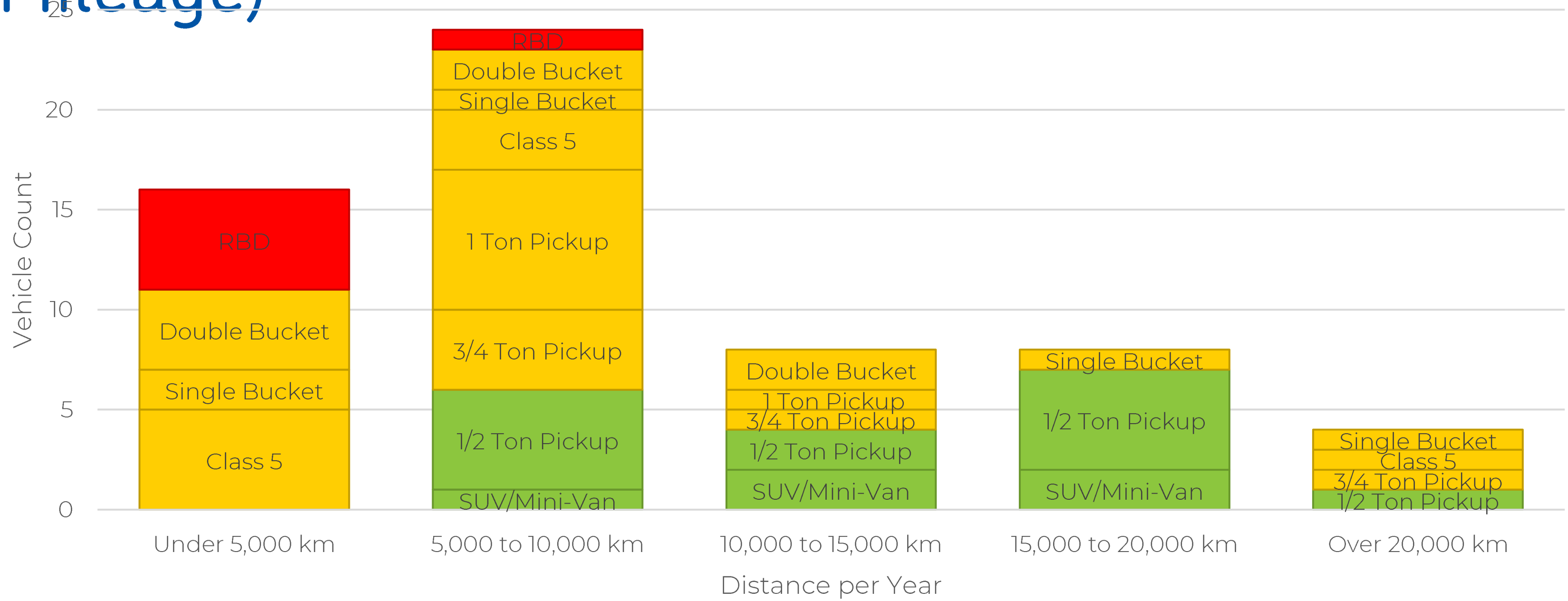
- The median vehicle is 7 years old. Assuming a 15-year life, about half of the fleet will turn over by 2030

SYNERGY NORTH Fleet Overview (Lifetime Mileage)



- Some of the more easily electrified vehicles may be nearing end of life

SYNERGY NORTH Fleet Overview (Annual Mileage)



- The fuel and maintenance savings of electric vehicles scale with distance travelled
- Higher utilization vehicles can be the most cost-effective to electrify, provided range is not an issue

Fleet Electrification Cost Benefit Methodology

- The methodology use to determine cost-effectiveness is Total Cost of Ownership (TCO) assessment taking into consideration fixed and ongoing costs in a discounted cash flow model
- For each of the readily-electrified vehicle types, a new internal combustion engine (ICE) option is matched with a comparable battery electric vehicle (BEV), targeting the lowest cost options available

Vehicle Type	ICE Option	BEV Option
Half-Ton Truck	2022 Chevrolet Silverado 1500 Crew Cab 4WD	2022 Ford F-150 Lightning
SUV	2022 Hyundai Tuscon 4 WWD	2022 Chevrolet Bolt EUV

- Base case uses conservative assumptions:
    - No reduction in cost of BEVs relative to ICE over time
    - No ultra-low 2.5 cent/kWh TOU rate for overnight charging
    - No federal incentive (up to $5,000 per vehicle)

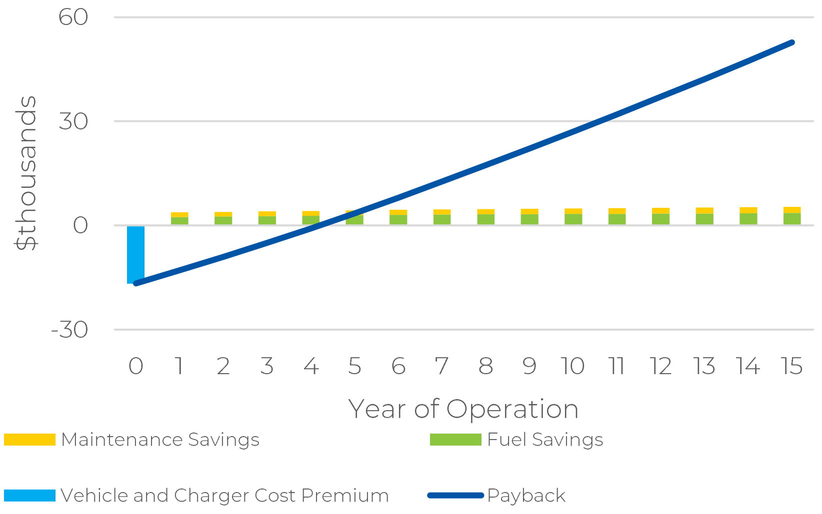
Fleet Electrification Cost Assumptions

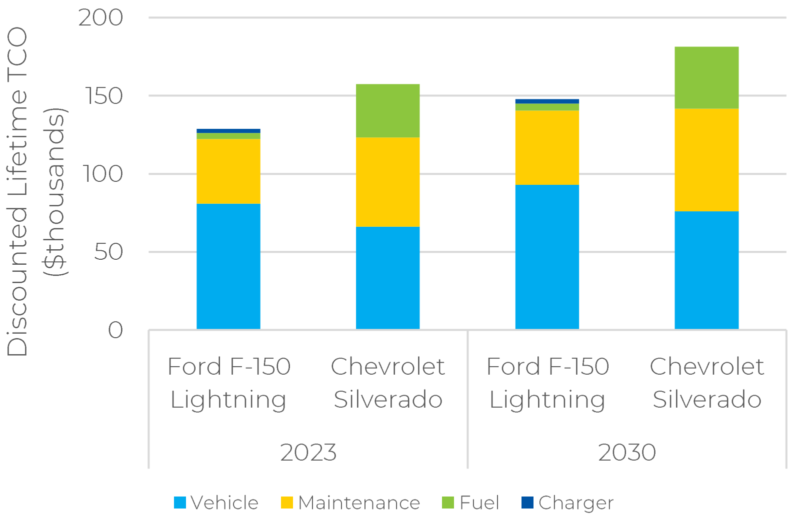
- Maintenance
  - Median of actual 2019-2021 maintenance cost ($/km) for vehicle type
  - EV maintenance is 73% of ICE maintenance*
- Financial
  - 2% inflation
  - 5.47% discount rate
  - Assume cash purchase, no financing
- Vehicle Use
  - 15 year useful life, zero residual value
  - Median of actual annual lifetime mileage for vehicle type

* Average of three studies: FleetAssist (78%), DRVE model for medium-duty vehicles (71%), and We Predict (69%). Note, SYNERGY NORTH maintenance costs are significantly higher than what is assumed in the TCO studies that Power Advisory reviewed

- New Vehicle MSRP and Fuel Efficiency
  - US dollar prices from Atlas Policy DRVE model
  - Canadian dollar MSRP validated with automaker
- Electricity Price
  - Current off-peak TOU rate of $0.082/kWh
- Gasoline Price
  - Median of CPI-adjusted regular gasoline price in Thunder Bay since 2010, without impact of carbon tax to date
  - Add projected impact of carbon tax and federal Clean Fuel Standard ($0.39/L and $0.10/L by 2030, respectively)
- Insurance
  - Assume equal insurance costs for ICE and BEV alternative

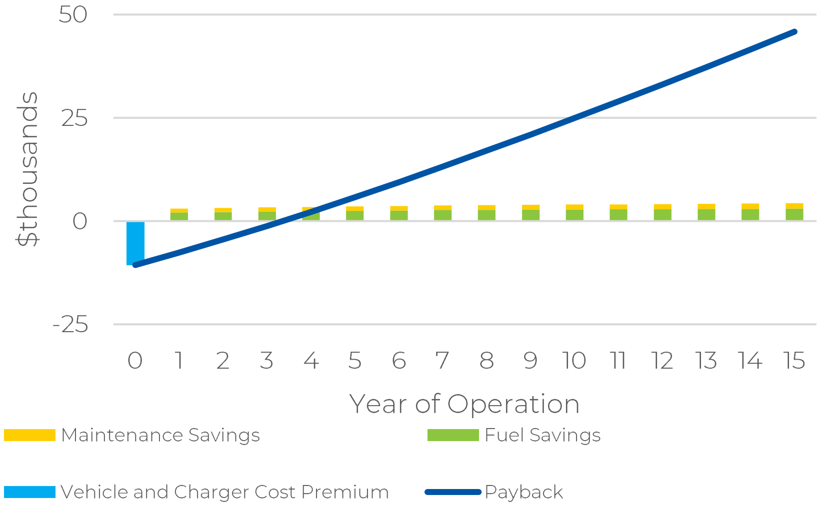
Cost Benefit Assessment: Electric Half-Ton Truck

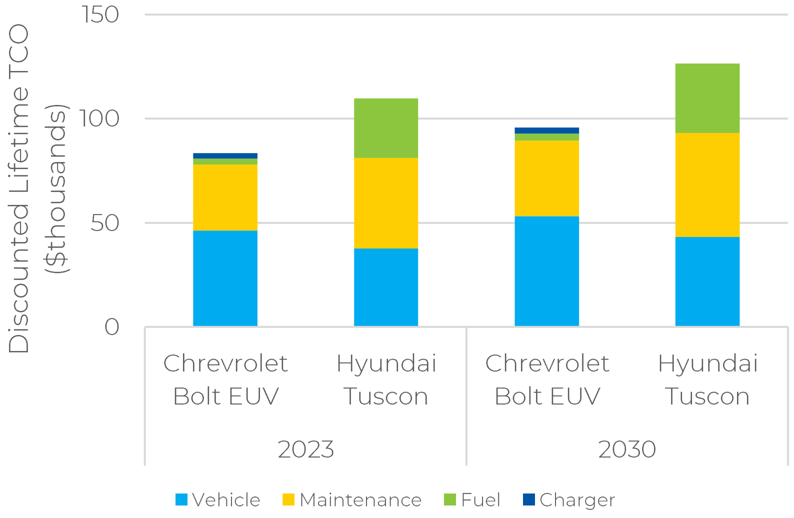




- Maintenance and fuel savings for the electric option pay back the battery electric price premium in slightly over 4 years, or slightly over 6 years when considering only fuel savings
- Total cost of ownership of electric option over a 15-year life is approximately 18% lower

Cost Benefit Assessment: Electric SUV





- Maintenance and fuel savings for the electric option pay back the battery electric price premium in about 3.5 years, or just under 5 years when considering only fuel savings
- Total cost of ownership of electric option over a 15-year life is approximately 24% lower

Fleet Electrification Discussion and Risks

- Supply chain, price risk, and vehicle availability:
  - Automakers are currently unable to keep up with demand for EVs, although they are investing heavily in expanding production
  - Lithium prices remain extremely high relative to the pre-2021 period, which has led to an increase in battery costs
  - Ford recently announced price increases for the Mach E of 6-13%, depending on model and battery size
- Suitability for utility work and real-world experience:
  - More detailed assessments of daily usage patterns are needed to confirm that available battery size and range are appropriate for demands
  - EVs in this assessment has 370 km range, which appears to be suitable compared to average daily use of ~50 km
  - A pilot electrification project could better inform how EVs fit into SYNERGY NORTH's operations, while also providing data (e.g., actual maintenance costs, charger installation costs) to support further electrification decisions

- *Given the conservative assumptions used, BEVs are expected to be cost-effective compared to ICE alternatives for light vehicles (half-ton trucks and SUVs) across a wide range of reasonable assumptions*

Fleet Electrification Next Steps

- Information Gathering and Partnerships
  - Request data from ENMAX on medium-duty truck electrification project (project will conclude April 2023)
  - SaskPower will take delivery of Terex all-electric bucket truck in 2022 and may be willing to share information
  - Continue to monitor announcements in electric heavy duty trucks
  - Review SYNERGY NORTH fleet utilization to determine:
    - Are there any vehicles which require a range greater than 370km or which are unable to charge nightly?
    - Are there any three-quarter and one-ton trucks which could be replaced with a lighter electric model such as the F-150 Lighting?
- Pilot Electrification
  - Plan to replace 2 to 3 older half-ton trucks and SUVs at end of life with electric alternatives in order to gather real-world data and experience
  - Priority vehicles are:
    - Units 56 and 58 (2009 Chevrolet Silverados with >130,000 km)
    - Unit 59 (2009 SUV with >200,000 km)
    - Units 84 and 92 (other 10 year old half-ton trucks with high mileage)

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ATTACHMENT 2-3:

2015 Kinectrics Study

THUNDER BAY HYDRO
2015 ASSET CONDITION ASSESSMENT

August 11, 2016

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THUNDER BAY HYDRO
2015 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418914-RA-0001-R00

August 11, 2016

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Revision History

Revision Number	Date	Comments	Approved
R00	August 11, 2016	Final Report	Yury Tsimberg

SUMMARY

In 2015 Thunder Bay Hydro Electricity Distribution Inc. (TBH) determined a need to perform a condition assessment of its key distribution assets. This would result in a quantifiable evaluation of asset condition, aid in prioritizing and allocating sustainment resources, and facilitate the development of a Distribution System Plan.

The asset groups included in the 2015 asset condition assessment (ACA) were as follows: substation transformers, breakers, wood poles, distribution transformers, overhead line switches, underground switches, and underground cables. For each asset category, the Health Index distribution was determined and a condition-based Flagged for Action plan was developed.

In terms of quantities of assets that need to be addressed, 25 kV wood poles require the most attention. Although only 3% of the population needs to be looked at this year, this amounts to over 450 poles. Approximately 9% of 4 kV wood poles were also flagged for action this year. Because of the considerably smaller population, however, this equates to just over 230 poles. Approximately 19% of pole mounted transformers were classified under the very poor category. As such, 170 transformers need to be addressed.

Many asset groups (i.e. distribution transformers, overhead switches, and underground cables) had only age data available. Data gaps for these and all other asset categories were identified. It is recommended that TBH begin collecting information to fill these data gaps and to use such information for future assessments.

It is important to note that the flagged for action plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence TBH's Distribution System Plan.

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I INTRODUCTION

Thunder Bay Hydro Electricity Distribution Inc. (TBH) is a private local distribution company responsible for distributing electricity to over 50,000 customers via a network of more than 1,300 kilometers of overhead and underground power lines in the City of Thunder Bay. TBH is owned by the City of Thunder bay and is operated by the Thunder Bay Hydro Board.

TBH recently recognized a need to perform an Asset Condition Assessment (ACA) on its key distribution assets. Such an assessment produces a quantifiable evaluation of asset condition, aids in prioritizing and allocating sustainment resources, and facilitates the development of a Distribution System Plan.

In 2015 TBH engaged Kinectrics Inc. (Kinectrics) to perform the first ACA on TBH's key distribution assets. This report presents the results of the study.

I.1 Objective and Scope of Work

The category and sub-categories of assets included in this study are as follows:

- Substation Transformers
  - 4 kV
  - 12 kV
- Breakers
- Wood Poles
  - 4 kV
  - 25 kV
- Distribution Transformers
  - Pad Mounted Transformers
  - Pole Mounted Transformers
  - Vault Transformers
- OH Switches
  - 4kV In-Line
  - 4kV Manual Air Break
  - 12 and 25kV In-Line
  - 12 and 25kV Manual Air Break
  - 25kV Motorized Load Break
- Underground Switches
  - 25kV Underground Load Break Switches
- Underground Cables
  - 4kV
  - 12 and 25kV

I.2 Deliverables

The deliverable in this study is a Report that includes the following information:

- Description of the Asset Condition Assessment methodology
- For each asset category the following are included:
  - Health Index formula
  - Age distribution
  - Health Index distribution
  - Condition-based Flagged For Action Plan
  - Assessment of data availability by means of a Data Availability Indicator (DAI) and a Data Gap analysis.

II ASSET CONDITION ASSESSMENT METHODOLOGY

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a parameter called "Oil Quality" may be a composite of parameters such as "Moisture", "Acid", "Interfacial Tension", "Dielectric Strength" and "Color".

In formulating a Health Index, condition parameters are ranked, through the assignment of *weights*, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of scores and weights, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DR$$

Equation 1

where

$$CPS_m = \frac{\sum_{n=1}^{\forall n} \beta_n (SCPS_n \times WSCP_n) \times DR_n}{\sum_{n=1}^{\forall n} \beta_n (WSCP_n)} \times DR_m$$

Equation 2

CPS	Condition Parameter (CP) Score, 0-4
WCP	Weight of Condition Parameter
α_m / β_n	Data availability coefficient for condition parameter
	(1 if input data available; 0 if not available)
SCPS	Sub-Condition Parameter (SCP) Score, 0-4
WSCP	Weight of Sub-Condition Parameter
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. In the Kinectrics methodology, a condition criteria scoring system of 0 through 4 is used. A score of 0 is the "worst" possible score; a score of 4 is the "best" score. I.e. $CPS_{max} = SCPS_{max} = 4$.

Note: From the formula, it can be seen that each parameter (condition or sub-condition) will have the following properties:

1. Weight
2. Availability coefficient (1 if asset has data for such parameter available; 0 otherwise)
3. Score (real value from 0 through 4)
4. Multiplier (real value)

II.1.1 Health Index Results

As stated previously, an asset's Health Index is given as a percentage, with 100% representing "as new" condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the *sample size*. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given. The Health Index categories are as follows:

Very Poor	Health Index < 25%
Poor	25 $\leq$ Health Index < 50%
Fair	50 $\leq$ Health Index <70%
Good	70 $\leq$ Health Index <85%
Very Good	Health Index $\geq$ 85%

Note that for critical asset groups, such as Power Transformers, the Health Index of each individual unit is given.

II.2 Condition Based Flagged for Action Plan

The condition based Flagged for Action Plan outlines the number of units that are expected to require attention in the next 20 years. The numbers of units are estimated using either a *proactive* or *reactive* approach. In the proactive approach, units are considered for action prior to failure, whereas the reactive approach is based on expected failures per year.

Both approaches consider asset failure rate and probability of failure. The failure rate is estimated using the method described in the subsequent section.

II.2.1 Failure Rate and Probability of Failure

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides a good model. This is based on the Gompertz-Makeham law of mortality. The original form of the failure function is:

$$f = \gamma e^{\beta t}$$

Equation 3

f	= failure rate per unit time
t	= time
γ, β	= constant that control the shape of the curve

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' experience in failure rate studies of multiple power system asset groups, the following variation of the failure rate formula has been adopted:

$$f(t) = e^{\beta(t-\alpha)}$$

Equation 4

f	= failure rate of an asset (percent of failure per unit time)
t	= age (years)
α, β	= constant parameters that control the rise of the curve

The corresponding cumulative probability of failure function is therefore:

$$P_f(t) = 1 - e^{-(f - e^{-\alpha\beta})/\beta}$$

Equation 5

P_f	= cumulative probability of failure

Different asset groups experience different failure rates and therefore different probabilities of failure. As such, the shapes of the failure and probability curves are different. The parameters α and β are used to control the exponential rise of these curves. For each asset group, the values of these constant parameters were selected to reflect typical useful lives for these assets.

Consider, for example, an asset class where at the ages of 45 and 65 the asset has cumulative probabilities of failure of 20% and 95% respectively. It follows that when using Equation 5, α and β are calculated as 72 and 0.131 respectively. As such, for this asset class the cumulative probability of failure equation is:

$$P_f(t) = 1 - e^{-(e^{\beta(t-\alpha)} - e^{-\alpha\beta})/\beta} \;=\; 1 - e^{-(e^{0.131(t-72)} - e^{-9.432})/0.131}$$

The failure rate and probability of failure graphs are as shown:

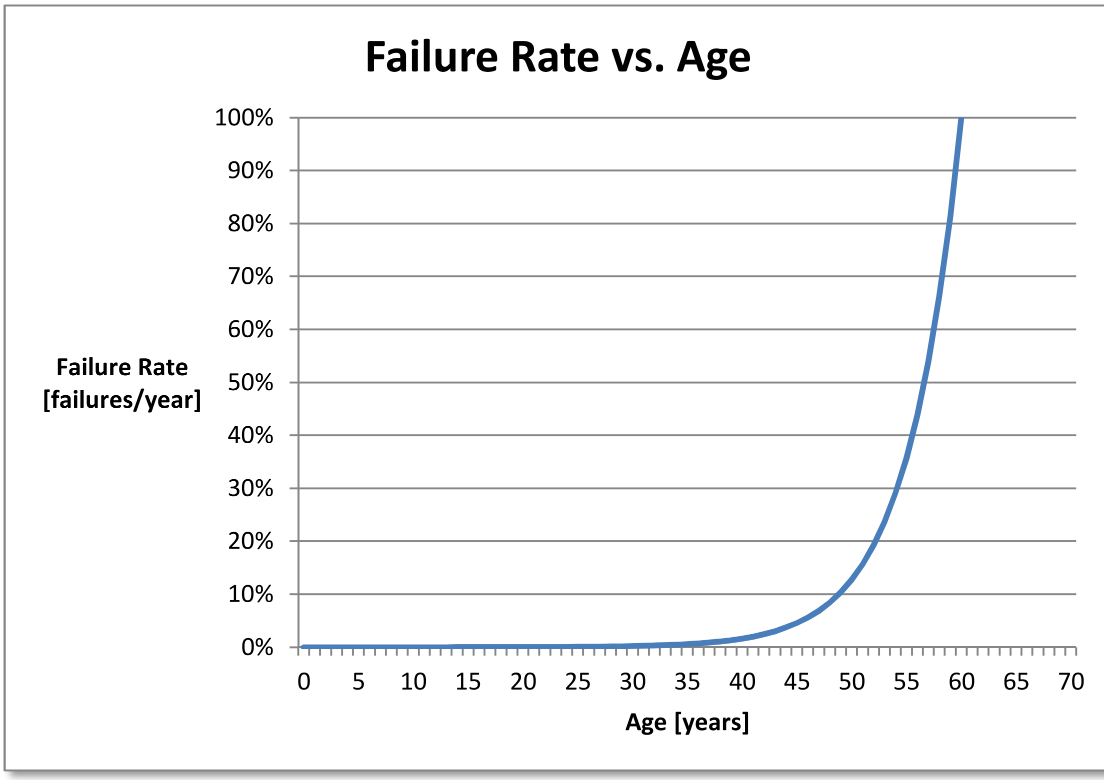

Figure II-1 Failure Rate vs. Age

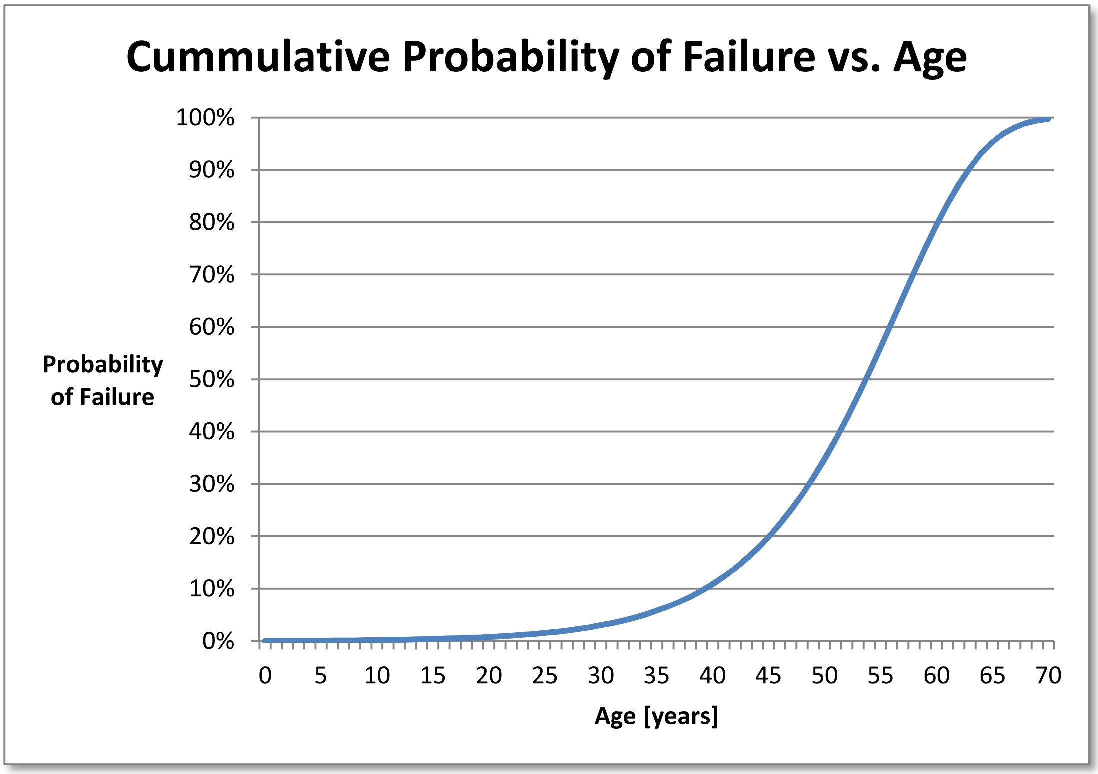

Figure II-2 Probability of Failure vs. Age

II.2.2 Projected Flagged for Action Plan Using a Reactive Approach

Because the consequences of failure are relatively small, many types of distribution assets are reactively replaced.

For such asset types, the number of units expected to be replaced in a given year are determined based on the asset's failure rates. The number of failures per year is given by Equation 4:

$$f(t) = e^{\beta(t-\alpha)}$$

with α and β determined from the probability of failure of each asset class.

An example of such a Flagged for Action Plan is as follows: Consider an asset distribution of 100 - 5 year old units, 20 – 10 year old units, and 50 - 20 year old units. Assume that the failure rates for 5, 10, and 20 year old units for this asset class are f_5 = 0.02, f_{10} = 0.05, f_{20} = 0.1 failures / year respectively. In the current year, the total number of replacements is 100(.02) + 20(0.05) + 50(0.1) = 2 + 1 + 5 = 8.

In the following year, the expected asset distribution is, as a result, as follows: 8 – 1 year old units, 98 – 6 year old units, 19 – 11 year old units, and 45 - 21 year old units. The number of replacements in year 2 is therefore 8(f_1) + 19(f_6) + 45(f_{11})+ 45(f_{21}).

Note that in this study the "age" used is in fact "effective age", or condition-based age if available, as opposed to the chronological age of the asset.

The Levelized Flagged for Action plan smooths or levelizes the peaks and valleys of the flagged for action plan.

II.2.3 Projected Flagged for Action Plan Using a Proactive Approach

For certain asset classes, the consequence of an asset failure is significant, and, as such, these assets are proactively addressed prior to failure. The proactive replacement methodology involves relating an asset's Health Index to its probability of failure by considering the stresses to which it is exposed.

Relating Health Index and Probability of Failure

If there are no dominant sources, it can be assumed that the stress to which an asset is exposed is not constant and will have a somewhat normal frequency distribution. This is illustrated by the probability density curve of stress below. The vertical lines in the figure represent condition or strength (Health Index) of an asset.

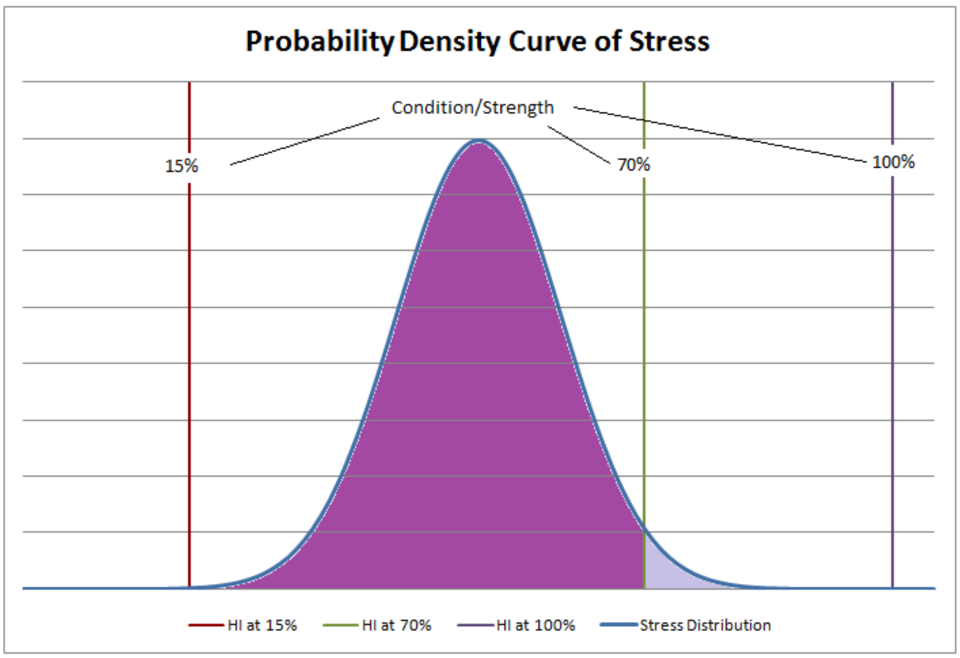

Figure II-3 Stress Curve

An asset is in as-new condition (100% strength) should be able to withstand most levels of stress. As the condition of the asset deteriorates, it may be less able to withstand higher levels of stress. Consider, for example, the green vertical line that represents 70% condition/strength. The asset should be able to withstand magnitudes of stress to left of the green line. If, however, the stress is of a magnitude to the right of the green line, the asset will fail.

To create a relationship between the Health Index and probability of failure, assume two "points" on the stress curve that correspond to two different Health Index values. In this example, assume that an asset that has a condition/strength (Health Index) of 100% can withstand all magnitudes of stress to the left of the purple line. It then follows that probability that an asset in 100% condition will fail is the probability that the magnitude of stress is at levels to the right of the purple line. This corresponds to the area under the stress density curve to the right of the purple line. Similarly, if it assumed that an asset with a condition of 15% will fail if subjected to stress at magnitudes to the right of the red line, the probability of failure at 15% condition is the area under the stress density curve to the right of the red line.

The probability of failure at a particular Health Index is found from plotting the Health Index on X-axis and the area under the probability density curve to the right of the Health Index line on Y-axis, as shown on the graph of the figure below.

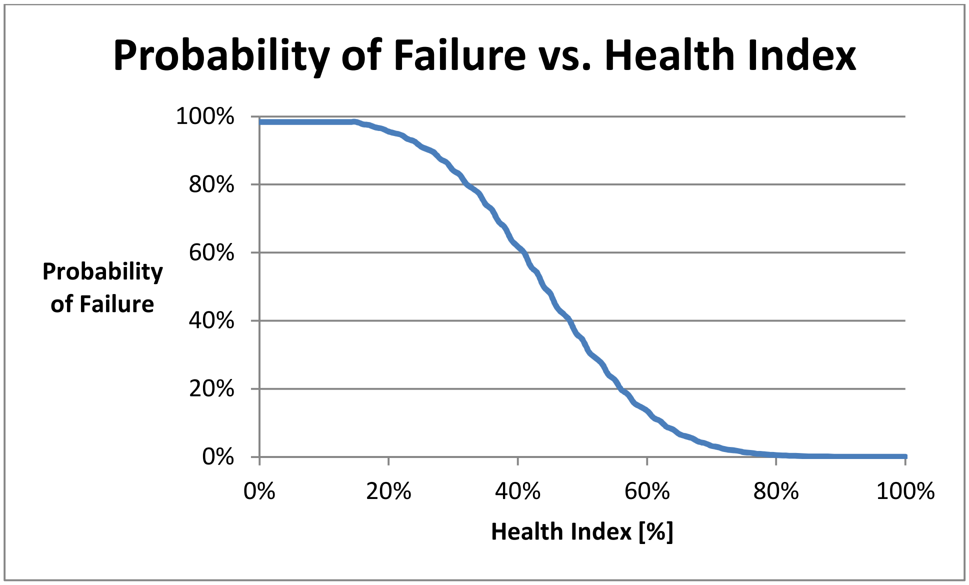

Figure II-4 Probability of Failure vs. Health Index

Condition-Based Flagged for Action Plan

To develop a Flagged for Action Plan, the risk of failure of each unit must be quantified. Risk is the product of a unit's probability of failure and its consequence of failure. The probability of failure is determined by an asset's Health Index. In this study, the metric used to measure consequence of failure is referred to as *criticality*.

Criticality may be determined in numerous ways, with monetary consequence or degree of risk to corporate business values being examples. For Substation Transformers, factors that impact criticality may include things like number of customers or location. The higher the criticality value assigned to a unit, the higher is it's consequence of failure.

In this study, it is assumed that the unit that has the highest relative consequence of failure has a criticality of 1.43. When its risk value, the product of its probability of failure and criticality, is greater than or equal to 1, the unit is flagged for action. In this case, if the unit with the criticality value of 1.43 has a POF = 70%, its risk will be 1.43*0.7 = 1 and it will be flagged for action.

II.3 Data Assessment

The condition data used in this study were provided by TBH and included the following:

- Test Results (e.g. Oil Quality, DGA, PCB)
- Inspection Records via Non-Conformance Logs
- Loading
- Make, Model, and Type
- Age

There are two components that assess the availability and quality of data used in this study: data availability indicator (DAI) and data gap.

II.3.1 Data Availability Indicator (DAI)

The Data Availability Indicator (DAI) is a measure of the amount of condition parameter data that an asset has, as measured against the condition parameters included in the Health Index formula. It is determined by the ratio of the weighted condition parameters score and the subset of condition parameters data available for the asset over the "best" overall weighted, total condition parameters score. The formula is given by:

$$DAI = \frac{\sum_{m=1}^{\forall m} (DAI_{CPS\ m} \times WCP_m)}{\sum_{m=1}^{\forall m} (WCP_m)}$$

Equation 6

where

$$DAI_{CPSm} = \frac{\sum_{n=1}^{\forall n} \beta_n \times WCFn}{\sum_{n=1}^{\forall n} (WCPFn)}$$

Equation 7

DAI_{CPSm}	Data Availability Indicator for Condition Parameter m with n Condition Parameter Factors (CPF)
β_n	Data availability coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)
$WCPF_n$	Weight of Condition Parameter Factor n
DAI	Overall Data Availability Indicator for the m Condition Parameters
WCP_m	Weight of Condition Parameter m

For example, consider an asset with the following condition parameters and sub-condition parameters:

Condition Parameter		Condition Parameter Weight (WCP)	Sub-Condition Parameter		Sub-Condition Parameter Weight (WCF)	Data Available? (β = 1 if available; 0 if not)
m	Name		n	Name		
1	A	1	1	A_1	1	1
2	B	2	1	B_1	2	1
			2	B_2	4	1
			3	B_3	5	0
3	C	3	1	C_1	1	0

The Data Availability Indicator is calculated as follows:

DAI_{CP1} = (1*1) / (1) = 1
DAI_{CP2} = (1*2 + 1*4 + 0*5) / (2 + 4 + 5) = 0.545
DAI_{CP3} = (0*1) / (1) = 0

$DAI = (DAI_{CP1}*WCP_1 + DAI_{CP2}*WCP_2 + DAI_{CP3}*WCP_3) / (WCP_1 + WCP_2 + WCP_3)$
= (1*1 + 0.545*2 + 0*3) / (1 + 2 + 3)
= 35%

An asset with all condition parameter data represented will, by definition, have a DAI value of 100%. In this case, an asset will have a DAI of 100% regardless of its Health Index score. Provided that the condition parameters used in the Health Index formula are of good quality and there are little data gaps, there will be a high degree of confidence that the Health Index score accurately reflects the asset's condition.

II.3.2 Data Gap

The Health Index formulations developed and used in this study are based only on TBH's available data. There are additional parameters or tests that TBH may not collect but that are important indicators of the deterioration and degradation of assets. The set of unavailable data are referred to as data gaps. I.e. A data gap is the case where none of the units in an asset group has data for a particular item. The situation where data is provided for only a sub-set of the population is not considered as a data gap.

As part of this study, the data gaps of each asset category are identified. In addition, the data items are ranked in terms of importance. There are three priority levels, the highest being most indicative of asset degradation.

Priority	**Description**	**Symbol**
High	Critical data; most useful as an indicator of asset degradation	✯ ✯ ✯
Medium	Important data; can indicate the need for corrective maintenance or increased monitoring	✯ ✯
Low	Helpful data; least indicative of asset deterioration	✯

It is generally recommended that data collection be initiated for the most critical items because such information will result in higher quality Health Index formulas.

The more critical and important data included in the Health Index formula of a certain asset group, and the higher the Data Availability Indicator of a particular unit in that group, the higher the confidence in the Health Index calculated for the particular unit.

If an asset group has significant data gaps and lacks good quality condition, there is less confidence that the Health Index score of a particular unit accurately reflects its condition, regardless of the value of its DAI.

To facilitate the incorporation of data gap items into improved Health Index formulas for future assessments, the data gaps items are presented in this report as sub-condition parameters. For each item, the parent condition parameter is identified. Also given are the object or component addressed by the parameter, a description of what to assess for each component or object, and the possible source of data.

The following is an example for "Tank Corrosion" on a Pad-Mounted Transformer:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	✯ ✯	Oil Tank	Tank surface rust or deterioration due to environmental factors	Visual Inspection

III RESULTS

This section summarizes the findings of this study.

III.1 Health Index Results

A summary of the Health Index evaluation results is shown in Table III-1. For each asset category the population, sample size (number of assets with sufficient data for Health Indexing), and average age are given. The average Health Index and distribution are also shown. A summary of the Health Index distribution for all asset categories are also graphically shown in **Error! Reference source not found.**. Note that the Health Index distribution percentages are based on the asset group's sample size.

The 4 kV underground cables, on average as an asset group, were found to be in the worst condition. A total of 34% were in very poor condition, where another 14% were found in poor condition. This is primarily because with the average age of the population at 43 years, the population is fairly old. However, since the population size is minimal (44 conductor-km), this is not a significant concern.

A large percentage of overhead switches, 14%, were classified as very poor; another 5% were found to be in poor condition. Many distribution transformers were also found to be in bad condition. Approximately 9%, 19%, and 8% of pad-mounted, pole-mounted, and vault transformers respectively were classified under the very poor category. These include units that are leaking and that contain PCBs.

The wood pole asset category is also concerning. A total of 10% of all wood poles are in poor or very poor condition.

III.2 Condition-Based Flagged for Action Plan

When there is a large quantity of assets that are at or near the end of their service lives, there may be large quantities of assets flagged for action in the first year. This represents a "backlog" of assets that required attention from past years. As it would not be feasible or practical for a utility to address all assets immediately, a levelized flagged for action plan, where quantities to address are spread over subsequent years, is also given. The unlevelized and levelized flagged for action plans are shown in Table III-2, Table III-3, Figure III-6, and

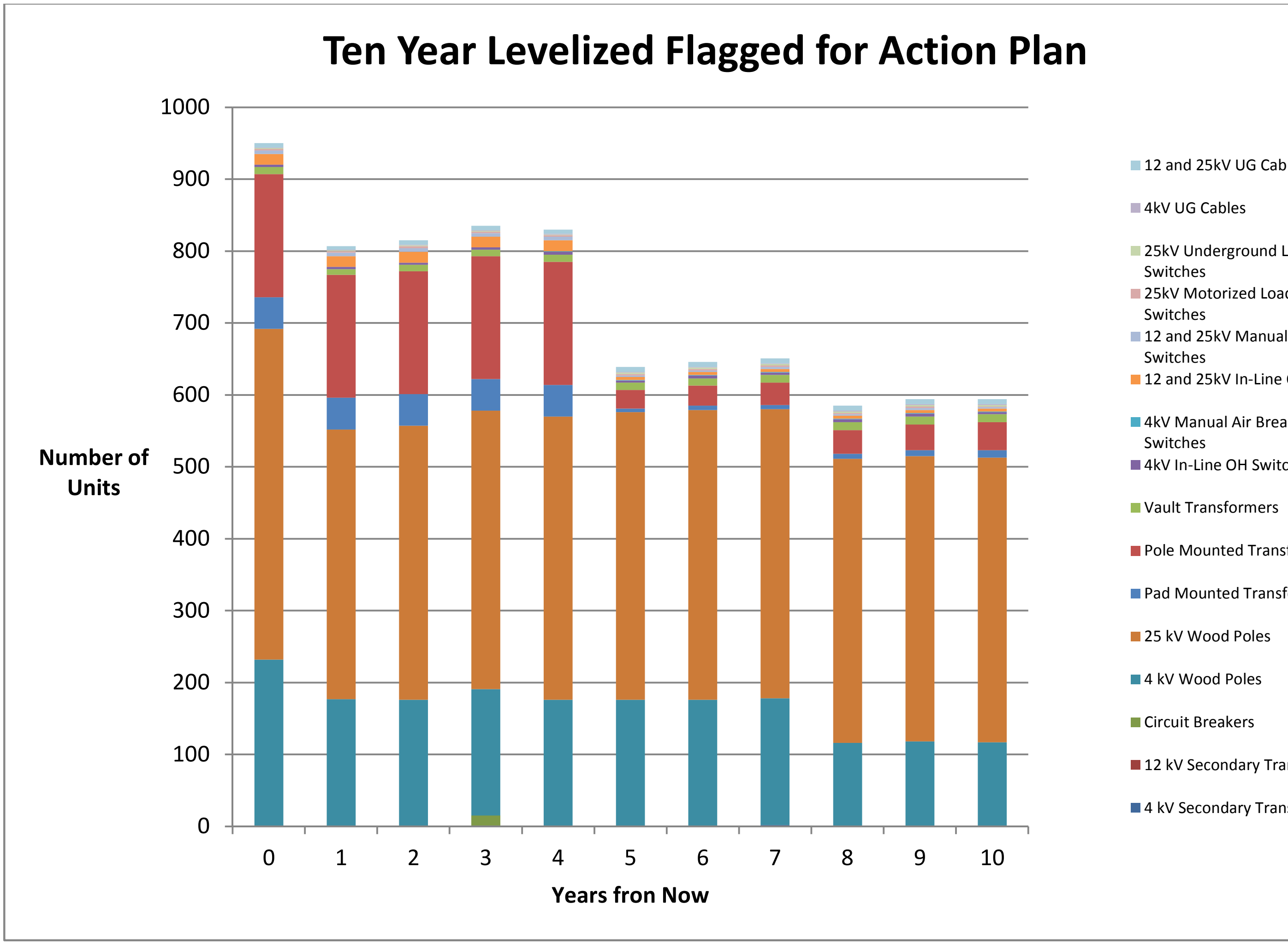

Figure III-7.

In terms of quantities of assets that need to be addressed, 25 kV wood poles require the most attention. Although only 3% of the population needs to be looked at in the first year (per the Levelized Plan in Table III-2), this amounts to over 450 poles. Approximately 6% of 4 kV wood poles were also flagged for action in the first year. Because of the considerably smaller population, however, this equates to just over 230 poles. Pole mounted transformers also have large quantities requiring action in year 1. Per the Levelized Plan, more than 170 transformers (4% of the population) are flagged.

Table III-1 Health Index Results Summary

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	
Station Transformers	All	23	23	88%	0%	4%	9%	4%	83%	52
	4 kV	17	17	86%	0%	6%	6%	12%	76%	54
	12 kV	6	6	94%	0%	0%	0%	0%	100%	47
Breakers	Breakers	77	77	72%	0%	18%	23%	12%	47%	56
Wood Poles	All	19813	19813	75%	1%	9%	34%	21%	34%	28
	4 kV	3862	3862	63%	4%	22%	39%	21%	15%	36
	25 kV	15951	15951	77%	< 1%	6%	33%	21%	39%	27
Distribution Transformers	Pad Mounted Transformers	2206	2206	87%	9%	1%	2%	12%	75%	25
	Pole Mounted Transformers	4143	4141	81%	19%	1%	1%	1%	77%	29
	Vault Transformers	285	285	78%	8%	3%	15%	26%	49%	33
OH Switches	All	729	305	76%	14%	5%	10%	12%	60%	32
	4kV In-Line	101	46	71%	26%	0%	9%	11%	54%	32
	4kV Manual Air Break	7	2	70%	0%	50%	0%	0%	50%	32
	12 and 25kV In-Line	399	148	80%	11%	7%	5%	8%	70%	31
	12 and 25kV Manual Air Break	183	74	78%	14%	4%	7%	9%	66%	33
	25kV Motorized Load Break	39	10	67%	10%	20%	20%	10%	40%	39
Underground Switches	25kV Underground Load Break Switches	80	30	81%	0%	13%	17%	3%	67%	31
Underground Cables*	All	432	374	80%	3%	3%	31%	4%	60%	29
	4kV	44	29	44%	34%	14%	21%	0%	31%	43
	12 and 25kV	387	344	84%	< 1%	2%	32%	4%	63%	28

* data is in conductor-km

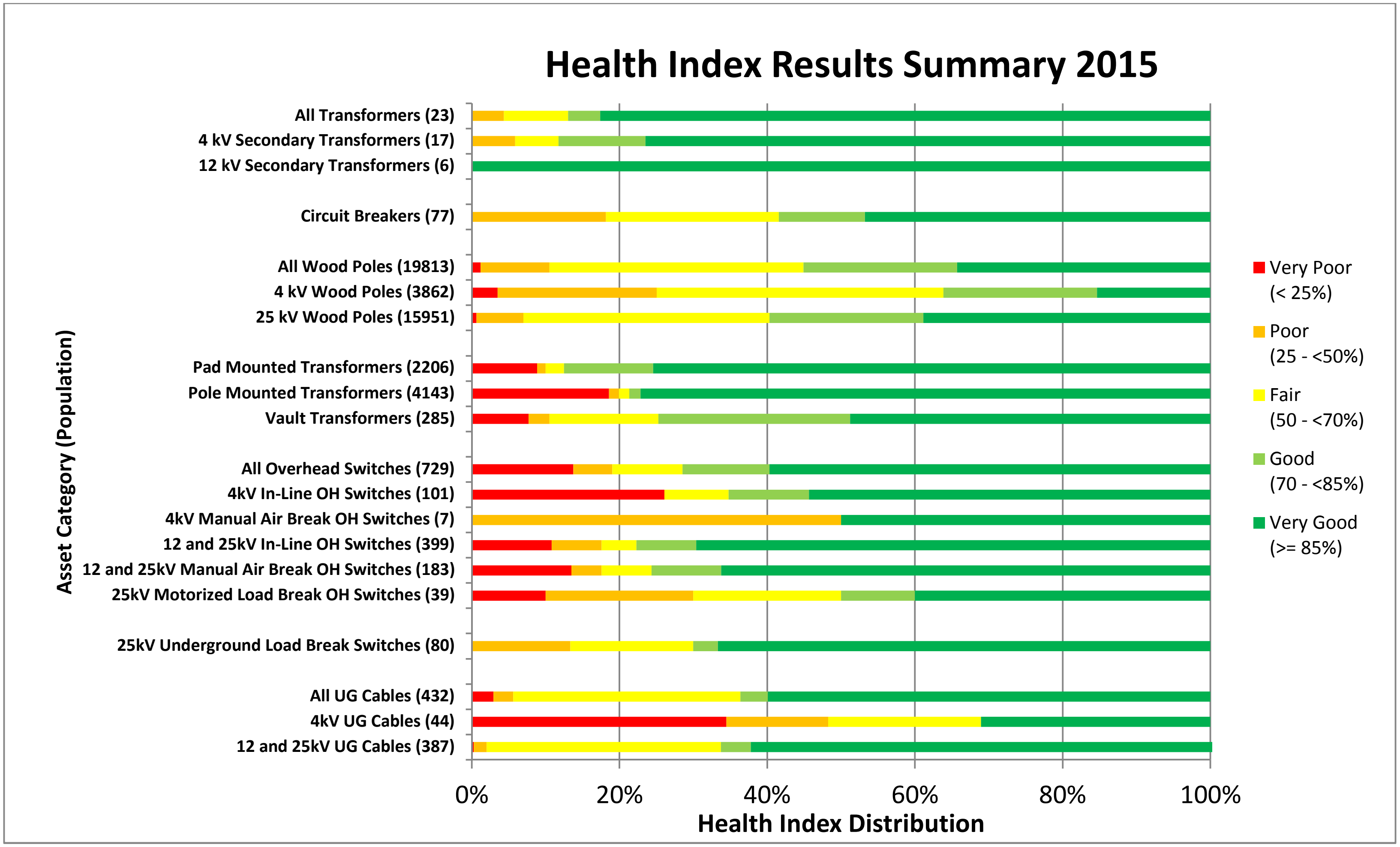

Figure III-5 Health Index Results Summary (Graphical)

Table III-2 Total Year 1 and 10-Year Total Flagged for Action Plan

Asset Category		10 Year Unlevelized Flagged for Action Total				10 Year LEVELIZED Flagged for Action Total				Replacement Strategy
		First Year		10 Year		First Year		10 Year		
		Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	
Substation Transformers	4 kV Secondary Transformers	0	0%	3	18%	0	0%	3	18%	proactive
	12 kV Secondary Transformers	0	0%	0	0%	0	0%	0	0%	proactive
Circuit Breakers	Circuit Breakers	0	0%	14	18%	0	0%	14	18%	proactive
Wood Poles	4 kV Wood Poles	364	9%	1636	42%	232	6%	1636	42%	proactive
	25 kV Wood Poles	544	3%	3964	25%	460	3%	3964	25%	proactive
Distribution Transformers	Pad Mounted Transformers	204	9%	240	11%	44	2%	240	11%	proactive
	Pole Mounted Transformers	625	15%	974	24%	171	4%	974	24%	reactive
	Vault Transformers	14	5%	93	33%	10	4%	93	33%	reactive
Overhead Switches	4kV In-Line OH Switches	3	3%	36	36%	3	3%	36	36%	reactive
	4kV Manual Air Break OH Switches	0	0%	4	57%	0	0%	4	57%	reactive

Asset Category		10 Year Unlevelized Flagged for Action Total				10 Year LEVELIZED Flagged for Action Total				Replacement Strategy
		First Year		10 Year		First Year		10 Year		
		Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	Quantity	Percentage	
	12 and 25kV In-Line OH Switches	30	8%	92	23%	15	4%	92	23%	reactive
	12 and 25kV Manual Air Break OH Switches	20	11%	36	20%	5	3%	36	20%	reactive
	12 and 25kV Motorized Load Break OH Switches	0	0%	16	41%	2	5%	16	41%	reactive
Underground Switches	25kV Underground Load Break Switches	0	0%	13	16%	1	1%	13	16%	reactive
Underground Cables*	4kV UG Cables	2	5%	4	9%	1	2%	4	9%	reactive
	12 and 25kV UG Cables	4	1%	59	15%	6	2%	59	15%	reactive

* data is in conductor-km

Table III-3 Ten Year Flagged for Action Plan

Replacement Year	Type (L = Levelized; Blank = Unlevelized)	Asset Category															
		Substation Transformers		Circuit Breakers	Wood Poles		Distribution Transformers			Overhead Switches					Underground Switches	Underground Cables*	
		4 kV Secondary Transformers	12 kV Secondary Transformers	Circuit Breakers	4 kV Wood Poles	25 kV Wood Poles	Pad Mounted Transformers	Pole Mounted Transformers	Vault Transformers	4kV In-Line OH Switches	4kV Manual Air Break OH Switches	12 and 25kV In-Line OH Switches	12 and 25kV Manual Air Break OH Switches	25kV Motorized Load Break OH Switches	25kV Underground Load Break Switches	4kV UG Cables	12 and 25kV UG Cables
0	L	0	0	0	232	460	44	171	10	3	0	15	5	2	1	1	6
		0	0	0	364	544	204	625	14	3	0	30	20	0	0	2	4
1	L	0	0	0	177	375	44	171	8	3	0	15	5	2	1	1	5
		0	0	0	253	473	7	130	9	2	0	13	5	0	5	0	4
2	L	0	0	0	176	381	44	171	9	3	0	15	5	3	1	1	6
		0	0	0	210	447	3	42	10	7	0	8	2	4	0	1	6
3	L	1	0	14	176	387	44	171	9	3	0	15	5	2	1	1	6
		1	0	14	182	424	2	30	8	3	0	22	0	8	1	0	7
4	L	0	0	0	176	394	44	171	10	4	1	15	5	2	1	1	6
		0	0	0	153	412	2	28	10	2	0	0	0	0	0	0	7
5	L	0	0	0	176	400	5	26	10	3	1	4	2	2	2	1	7
		0	0	0	132	409	5	28	9	2	0	8	5	0	1	0	8
6	L	0	0	0	176	403	6	28	10	4	1	4	2	2	2	1	7
		0	0	0	119	411	6	27	12	7	0	3	2	4	3	0	8
7	L	2	0	0	176	402	6	31	11	3	1	4	3	2	2	1	7
		2	0	0	112	416	5	32	10	3	0	5	2	0	2	0	8
8	L	0	0	0	116	395	7	33	11	4	1	4	2	2	2	1	7
		0	0	0	111	428	6	32	11	7	4	3	0	0	1	1	7
9	L	1	0	0	117	397	8	36	11	4	1	4	3	2	2	1	7
		1	0	0	114	425	5	36	11	2	0	3	5	0	1	0	9
10	L	0	0	0	117	396	10	39	11	3	1	4	2	1	2	1	7
		0	0	0	115	418	9	39	12	3	0	0	0	0	1	1	7

* data is in conductor-km

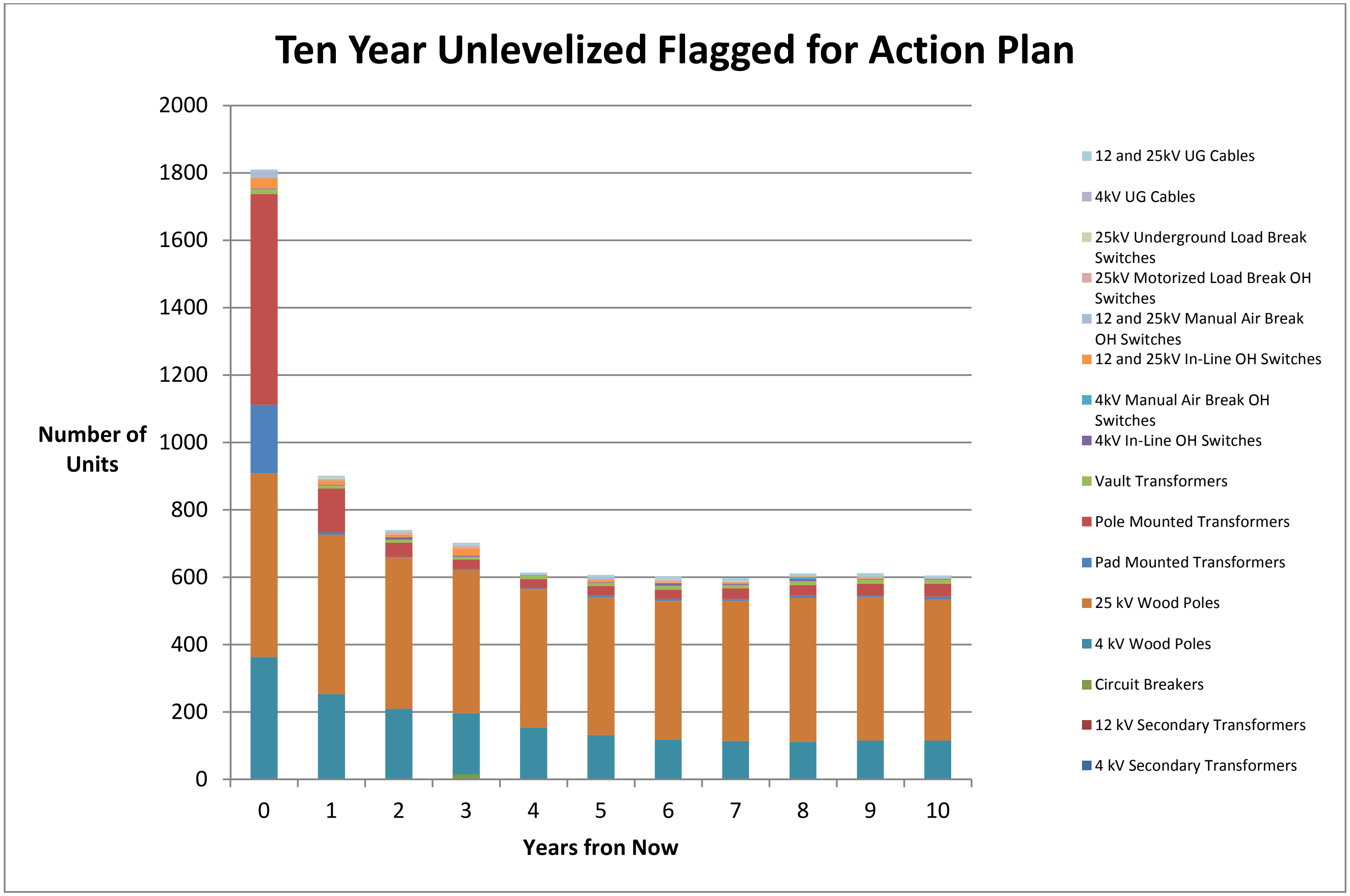

Figure III-6 Ten Year Unlevelized Flagged for Action Plan (Graphical)

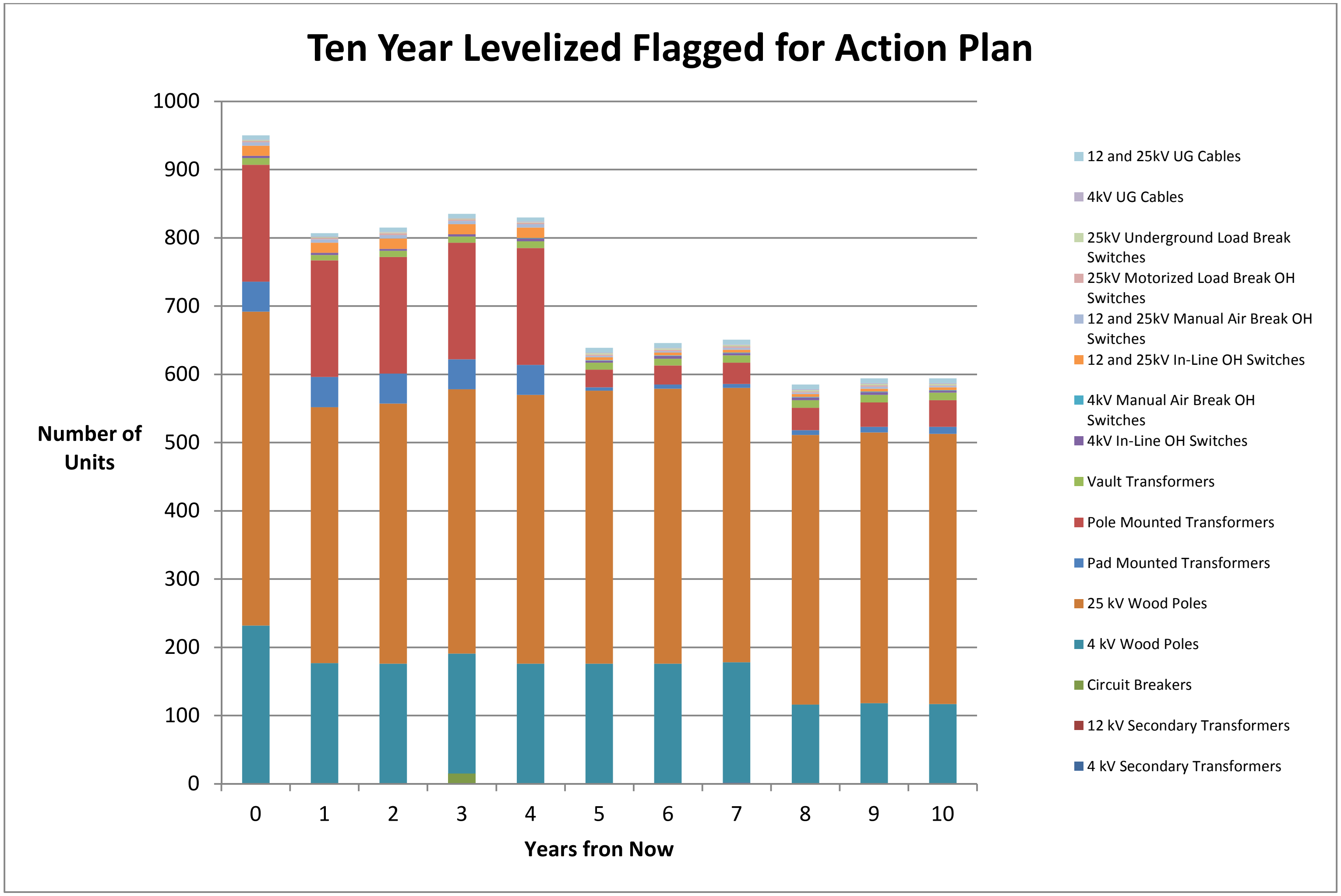

Figure III-7 Ten Year Levelized Flagged for Action Plan (Graphical)

III.3 **Data Assessment Results**

As mentioned described in Section II.3, the assessment of the available data was done by looking at the data availability indicator (DAI) and data gaps. Recall that the DAI is measurement that is relative to the information that TBH currently collects, whereas data gaps are information that TBH does not collect. As such, even if an asset group has a high DAI, this does not mean information for this asset group is complete. i.e. if there are numerous data gaps, the degree of confidence that the Health Index reflects true condition may still be low. Table III-4 shows the average DAI for each category. The Data Gap column indicates the extent of the data gap (i.e. “high” indicates that a significant amount of condition information can be collected for future assessments). Overall assessments for each asset category are summarized below. Additional details, including prioritized data gaps, are given in the data gap sections of Appendix A: Results for Each Asset Category.

Age, loading, oil quality and dissolved gas analysis tests were available for all Substation Transformers. Data that would be helpful for future assessments include power dissipation factor tests, inspection and/or corrective maintenance records.

For circuit breakers, age and maintenance reports that had information on the following were available: internal, closing, trip mechanisms; tolerance; close and trip timing; contacts; arc chute (Air Blast), heater and tank leak (oil); Insulation. The DAI for this asset group, however, is only 61%. Efforts should be made to ensure that the information is available for all breakers. Data that would be helpful include the operation counts, fault interruption counts, and fault level interrupted.

Age and overall risk rating based on inspection records were available for wood poles. Data gaps include more detailed inspection records and strength tests that give an objective, quantified assessment of the condition of wood poles.

Age, PCB content, and inspection records that provide information on transformer base, enclosure, leaks, and overall hazard condition were available for pad mounted transformers. Loading and inspection/corrective maintenance information related to the connections (elbows/inserts) would be helpful for future assessments.

Only age and PCB content were available for pole-mounted and vault transformers. Loading and inspection/corrective maintenance information related to transformer condition (e.g. leaks, tank/enclosure condition, corrosion, connections).

Age was the only information available for overhead and underground switches. Further, as can be seen from the low DAIs of these asset categories, fewer than half of the switches had age information. Operations records and inspection/corrective maintenance records should be collected (e.g. condition related to switch, operating mechanism, insulation, arc extinguishing mechanism). Such information would provide insight to actual condition.

Underground cables had only age information. However, fewer than half of the cable population had such information. TBH should consider diagnostic testing (e.g. insulation resistance, time domain reflectometry, AC Withstand, PD, Dielectric Spectroscopy/VLF Tan

Delta). Such information will provide good, objective condition data as input into the Health Index.

Table III-4 Data Assessment

Asset Category		Average DAI	Data Gap
Station Transformers	All	93%	Low-Medium
	4 kV	92%	
	12 kV	93%	
Breakers	Breakers	61%	Low-Medium
Wood Poles	All	100%	Medium-High
	4 kV	100%	
	25 kV	100%	
Distribution Transformers	Pad Mounted Transformers	85%	Low-Medium
	Pole Mounted Transformers	100%	Medium-High
	Vault Transformers	100%	Medium-High
OH Switches	All	42%	High
	4kV In-Line	46%	
	4kV Manual Air Break	29%	
	12 and 25kV In-Line	37%	
	12 and 25kV Manual Air Break	40%	
	12 and 25kV Motorized Load Break	26%	
Underground Switches	25kV Underground Load Break Switches	38%	High
Underground Cables	All	48%	High
	4kV	65%	
	12 and 25kV	47%	

IV CONCLUSIONS AND RECOMMENDATIONS

1. An Asset Condition Assessment was conducted for TBH's key distribution assets, namely substation transformers, breakers, wood poles, distribution transformers, overhead line switches, underground switches, and underground cables. For each asset category, the Health Index distribution was determined and a condition-based replacement plan was developed.

2. Of all the asset groups, 4kV underground cables were found, on average, to be in the worst condition. A total of 48% were found to be in poor or very poor condition. However, because of the small population, this is not a significant cause for concern.

3. A large percentage of overhead switches, 14%, were classified as very poor; another 5% were found to be in poor condition. Because the population of switches is relatively small, the number of assets flagged for action is not significant.

4. Approximately 19% of pole mounted transformers were classified under the very poor category. Per the levelized flagged for action plan over 170 transformers require action in the first year.

5. In terms of quantities of assets that need to be addressed, 25 kV wood poles require the most attention. Although only 3% of the population needs to be looked at in the first year, this amounts to over 450 poles.

   Approximately 6% of 4 kV wood poles were also flagged for action in the first year. Because of the considerably smaller population than the 25 kV poles, however, this equates to just over 230 poles.

6. Age and inspection information were available for substation transformers, breakers, wood poles, and pad-mounted transformers. Additionally substation transformers had loading and oil tests. Only age was available for pole-mounted transformers, vault transformers, overhead and underground switches, and underground cables. Further, the age was only available for less than half of the switches and cables.

7. It is recommended that the data availability indicator (DAI) for each asset category be brought to 100% and maintained at that level. i.e. Data for all condition parameters used in the HI formulas should be collected for all assets. The low DAIs of switches and cables are of particular concern.

8. Data gaps were identified for each asset category, prioritized in the order of importance, in the Appendix of this report. It is recommended that the data be gathered in prioritized manner. Data may be gathered from inspections or corrective maintenance records. Additional sources of data would come from testing (e.g. pole strength testing or cable testing).

9. Because only limited failure statistics was available at this time, an exponentially increasing failure rate and corresponding probability of failure model were assumed in this study. It is

recommended that TBH begin collecting failure information so failure models can be developed and used in future assessments.

10. It is important to note that the replacement plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence TBH's Asset Management Plan.

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APPENDIX A: RESULTS FOR EACH ASSET CATEGORY

1 Substation Transformers

1.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

1.1.1 Condition and Sub-Condition Parameters

Table 1-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	**Description**	**Weight (WCP)**	**De-Rating Multiplier (DR_CP)**	**m**	**Description**	**Weight (WSCP)**	**De-Rating Multiplier (DR_SCP)**	**SCP Criteria**
1	Insulation	**3**	**1**	1	Oil Quality (MT Oil)	2	**1**	Table 1-2
				2	Oil DGA (MT DGA)	3	**1**	Table 1-3
				3	Power Dissipation Factor (Doble)	0*	**1**	Table 1-4
				4	Bushing Issues	0*	**1**	Table 1-5
2	Cooling	**0***	**1**	1	Winding Temp Gauge	**0***	**1**	Table 1-5
3`	Sealing & Connection	**0***	**1**	1	Corrosion	0*	**1**	Table 1-5
				2	Paint	0*	**1**	Table 1-5
				3	Oil Leak	0*	**1**	Table 1-5
				4	Connection	0*	**1**	Table 1-5
				5	Grounding	0*	**1**	Table 1-5
4	Service Record	**5**	**1**	1	Loading	1	Table 1-6	Table 1-6
Overall HI De-Rating Multiplier (DR)				DGA Trend				Table 1-3
AGE Limiter				The final Health Index value will be limited by the asset age				Equation 8
*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.								

1.1.2 Condition Criteria

<u>Oil Quality</u>

The “Oil Quality” parameter is a composite of the following oil properties: moisture, dielectric strength, interfacial tension, color, and acidity.

Table 1-2 Oil Quality Test Criteria

Score	Description
4	Overall Factor is less than 1.2
3	Overall Factor between 1.2 and 1.5
2	Overall Factor is between 1.5 and 2.0
1	Overall Factor is between 2.0 and 3.0
0	Overall Factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

		Scores				
		1	2	3	4	Weight
Moisture PPM (T °C Corrected) (From DGA test)		<=20	<=30	<=40	>40	4
Dielectric Str. [kV] D877		>40	>30	>20	Less than 20	3
Interfacial Tension (IFT)* [dynes/cm]	230 kV ≤ V	>32	25-32	20-25	Less than 20	2 *
	69 kV <V< 230	>30	23-30	18-23	Less than 18	
	V ≤ 69 kV	>25	20-25	15-20	Less than 15	
Color		Less than 1.5	1.5-2	2-2.5	> 2.5	2
Acid Number*	230 kV ≤ V	Less than 0.03	0.03-0.07	0.07-0.1	>0.1	1 *
	69 kV <V< 230	Less than 0.04	0.04-0.1	0.1-0.15	>0.15	
	V ≤ 69 kV	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	

* Select the row applicable to the equipment rating

Overall Factor = $\dfrac{\sum Score_i \times Weight_i}{\sum Weight}$

For example if all data is available, Overall Factor = $\dfrac{\sum Score_i \times Weight_i}{12}$

<u>Oil DGA</u>

Table 1-3 Transformer DGA Criteria

Score	Description
4	DGA overall factor is less than 1.2
3	DGA overall factor between 1.2 and 1.5
2	DGA overall factor is between 1.5 and 2.0
1	DGA overall factor is between 2.0 and 3.0
0	DGA overall factor is greater than 3.0

In the case of a score other than 4, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score 3, 0.85 for score 2, 0.75 for score 1 and 0.5 for score 0.

Where the DGA overall factor is the weighted average of the following gas scores:

Dissolved Gas	Scores						
	1	2	3	4	5	6	Weight
H2	<=100	<=200	<=300	<=500	<=700	>700	**2**
CH4(Methane)	<=120	<=150	<=200	<=400	<=600	>600	**3**
C2H6(Ethane)	<=65	<=100	<=150	<=250	<=500	>500	**3**
C2H4(Ethylene)	<=50	<=80	<=150	<=250	<=500	>500	**3**
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	**5**
CO	<=350	<=700	<=900	<=1100	<=1300	>1300	**1**
CO2	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	**1**

$$\text{Overall Factor} = \frac{\sum Score_i \times Weight_i}{\sum Weight}$$

Winding Doble Test

Table 1-4 Winding Doble Test Criteria

Score	Description
4	power factor reading $\leq$ 0.5%
3	0.5% < power factor reading $\leq$ 0.7%
2	0.7% < power factor reading $\leq$ 1.0%
1	1.0% < power factor reading $\leq$ 2.0%
0	power factor reading > 2.0%

Visual Inspections

Table 1-5 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Loading History

Table 1-6 Loading History

Data: S1, S2, S3, …, SN recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

Age Limiter

The final Health Index value is limited by the age of the asset shown below:

Final Health Index = Minimum{ HI, $S_f(t)$ }

Equation 8

Where $S_f(t)$ is the survival function calculated as follows:

Assume that the failure rate Substation Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f(t) = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f(t) = 1 - \ P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 60 and 70 years the probability of failures (P_f) for Substation Transformers are 20% and 95% respectively results in the survival curve shown below.

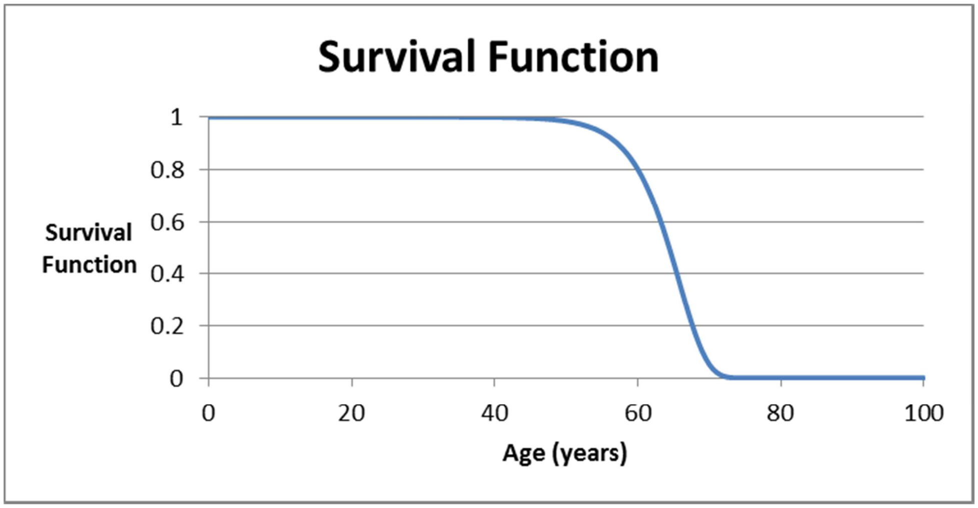

Figure 1-1 Substation Transformers Survival Function

1.2 Age Distribution

The average age of all in service units was 52. All transformers are more than 44 years old. The age distribution for in service Substation Transformers was as follows:

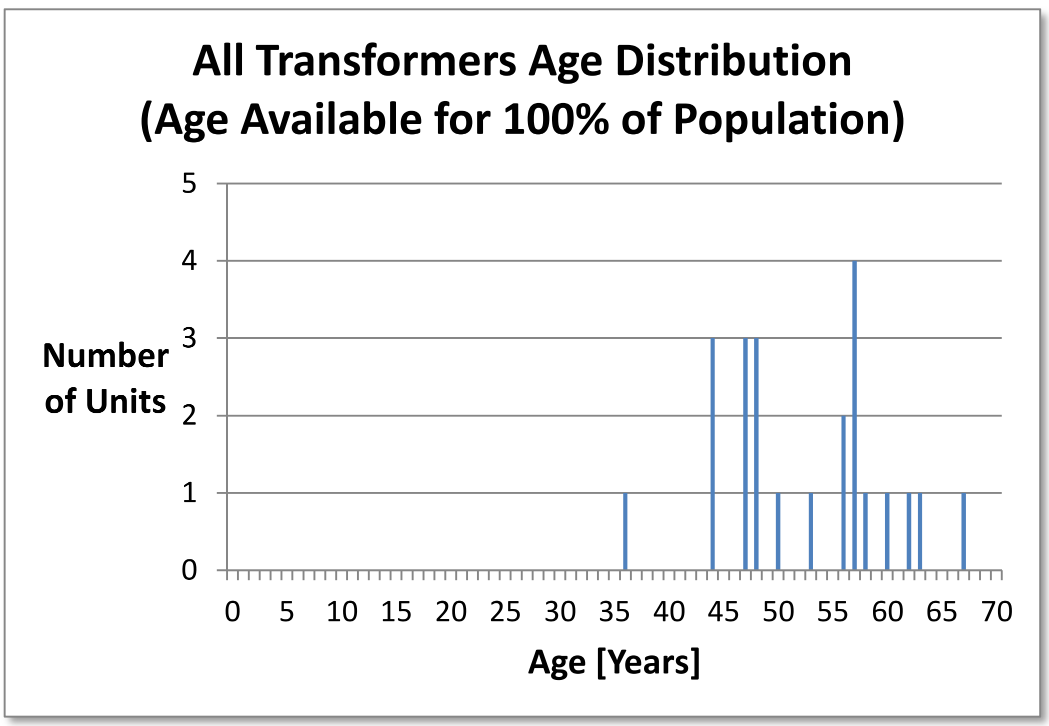

Figure 1-2 Substation Transformers Age Distribution

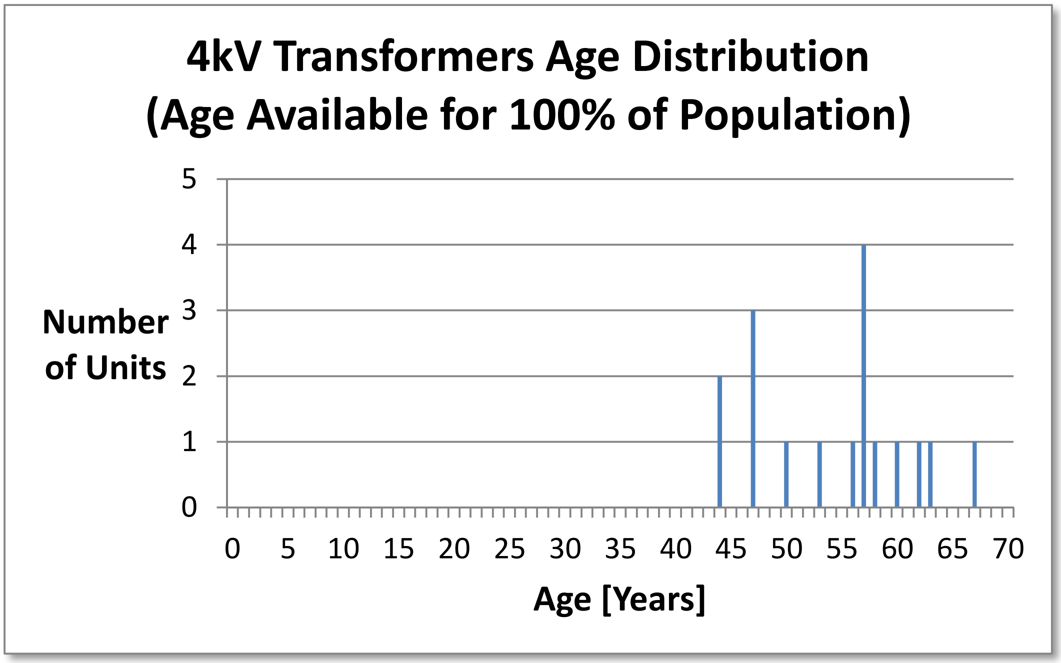

Figure 1-3 4KV Secondary Substation Transformers Age Distribution

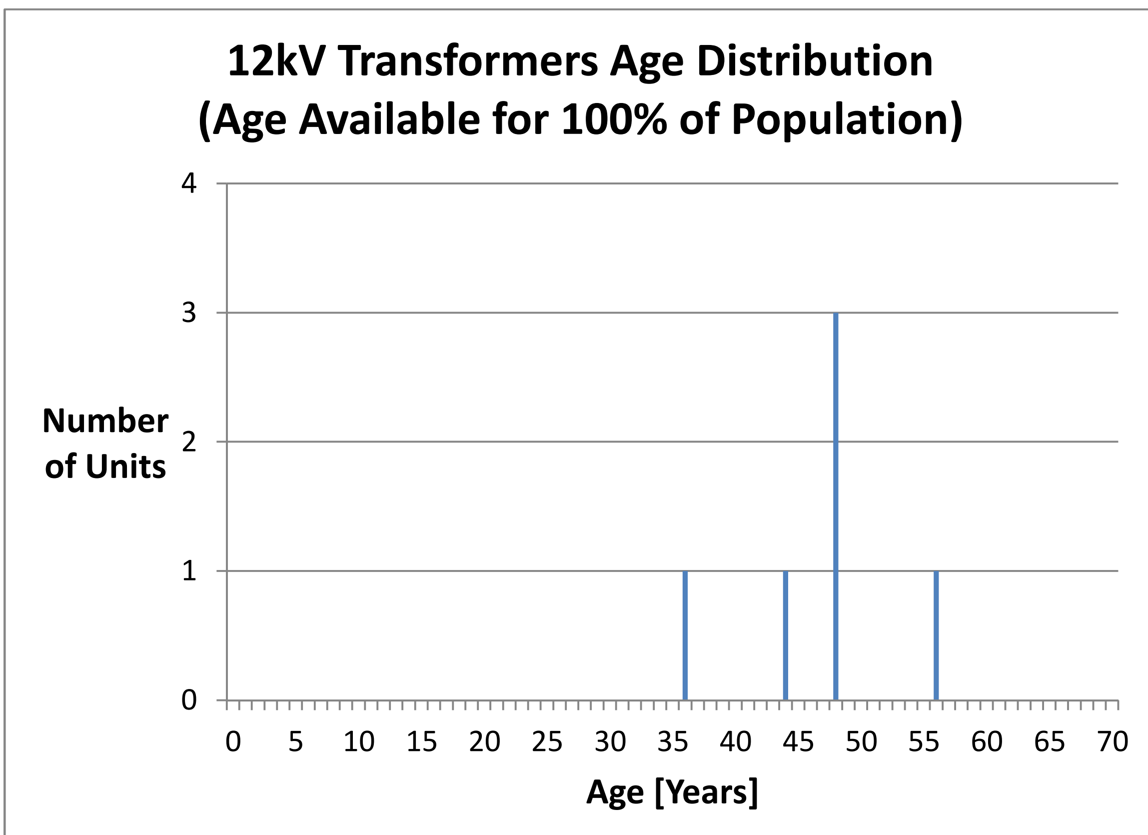

Figure 1-4 12KV Secondary Substation Transformers Age Distribution

1.1 Health Index Results

There are 23 in service Substation Transformers at TBH. Of these, all had sufficient data for Health Indexing.

The Health Index Distribution in terms of number of units and percentage of units are shown below. The average Health Index for this asset group was 88%. Only 1 was found to be in "poor" condition.

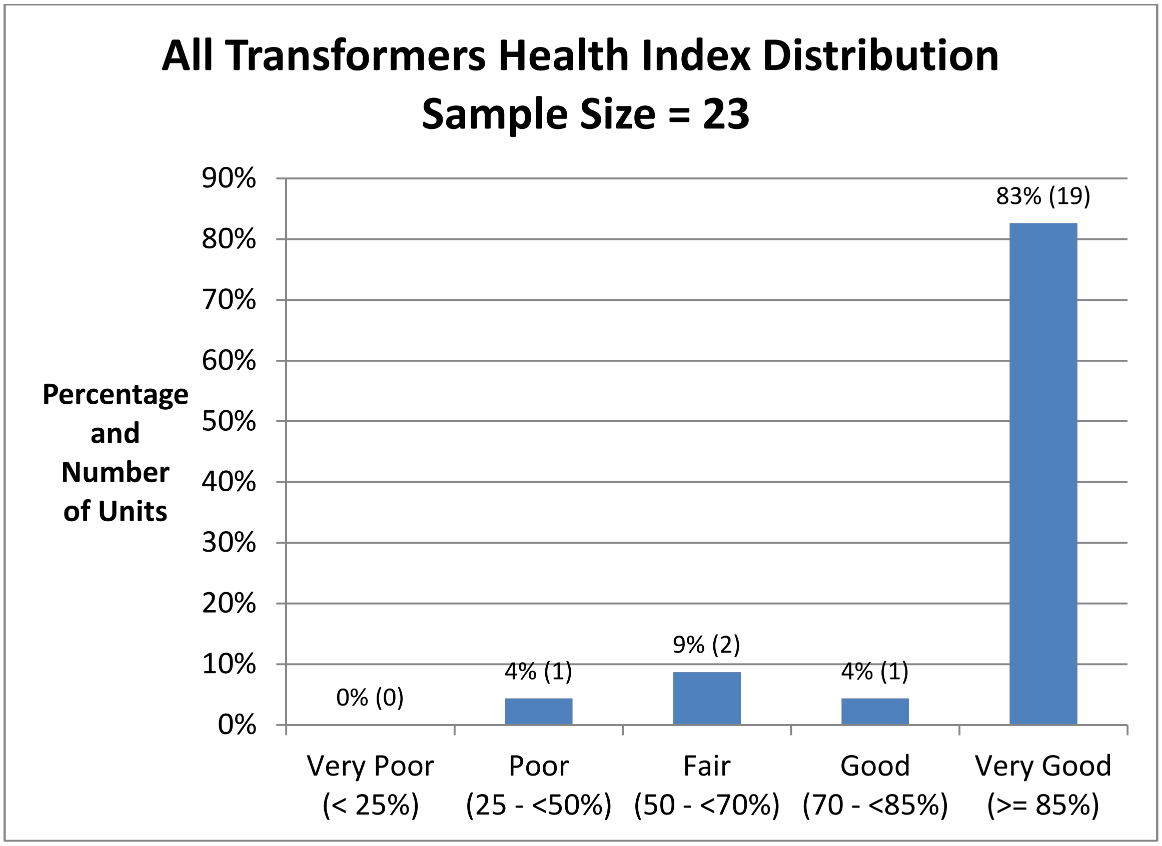

Figure 1-5 Substation Transformers Health Index Distribution

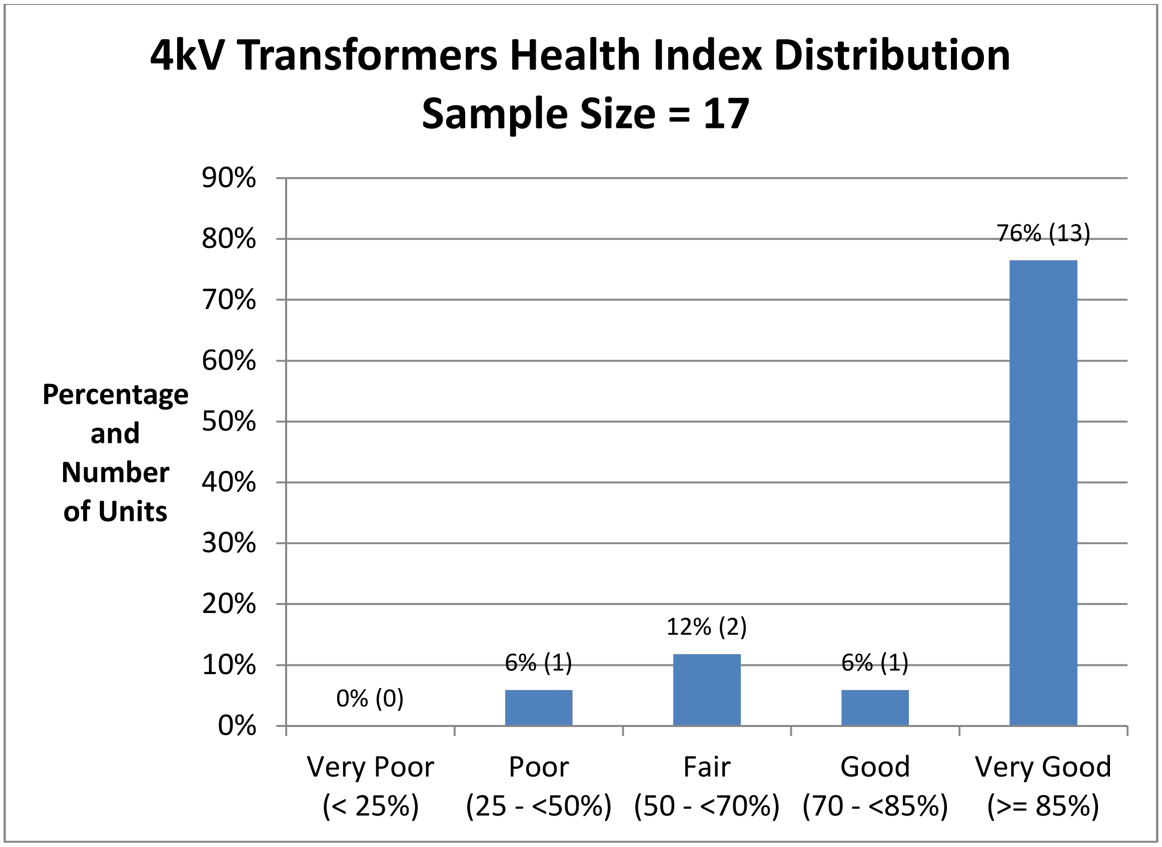

Figure 1-6 4KV Secondary Substation Transformers Health Index Distribution

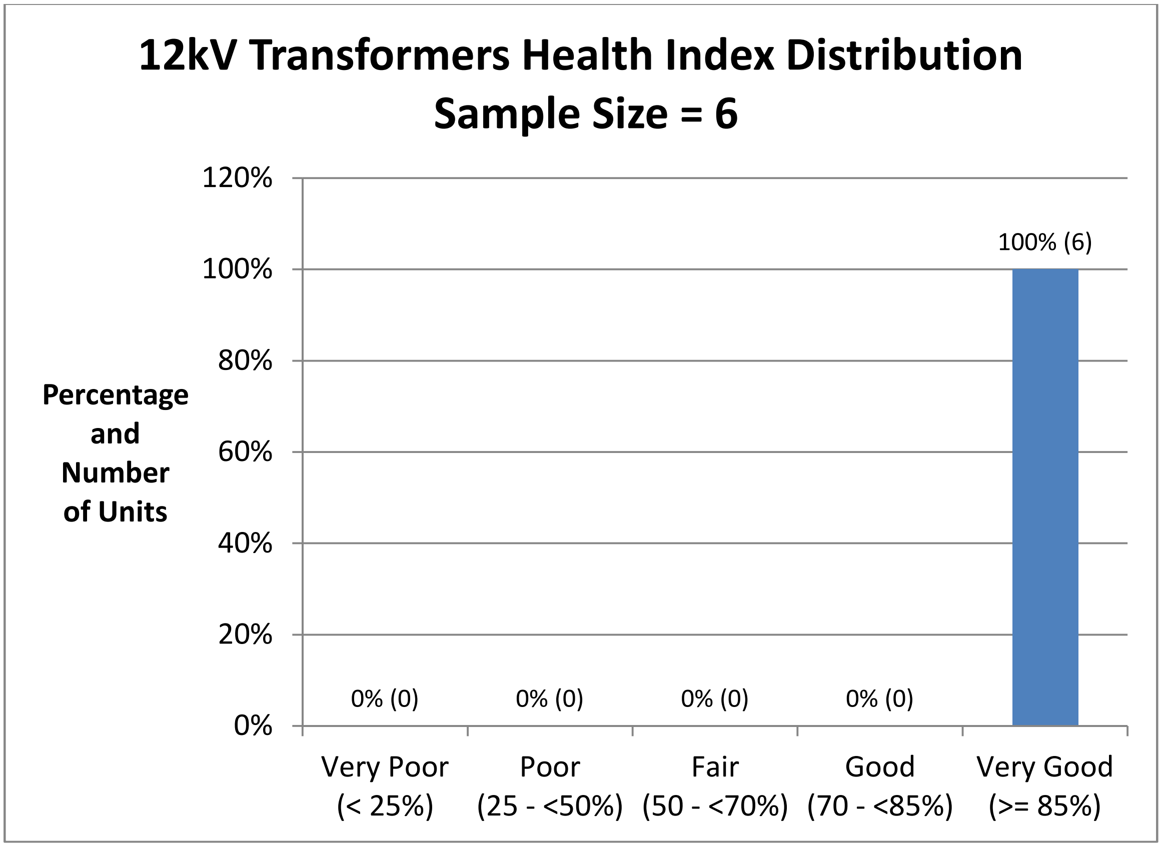

Figure 1-7 12KV Secondary Substation Transformers Health Index Distribution

1.2 Flagged for Action Plan

It is assumed that Substation Transformers are proactively replaced.

In this study, a unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one.

Each unit's criticality is defined as follows:

$$Criticality = (Criticality_{max} - Criticality_{min}) * Criticality\_Index + Criticality_{min}$$

where:

$Criticality_{max} = 1/(70\%) = 1.43$ (the units with highest relative importance should be replaced when their POF reaches 70%)

$Criticality_{min} = 1/(90\%) = 1.11$ (the units with lowest relative importance can wait until their POF reaches 95% to be replaced)

Similar to the Health Index (HI), the *Criticality Index* (CI) is a sum-product of scores and weights of parameters that represent a unit's consequence of failure. CI ranges from 0 to 100%, with 100% representing the unit with the highest possible consequence of failure.

$$Criticality\_Index = \frac{\sum_{i=1}^{\forall i}(SCRP_i \times WCRP_i)}{\sum_{i=1}^{\forall i}(WCRP_i)}$$

The Criticality Parameters (CRPs) and possible scoring system used in this study are shown below. Parameters, weights, and scoring systems will be unique to each utility and should be customized accordingly.

Criticality Parameter (CRP)	Description	Weight (WCRP)	Score (SCRP)	
Load Criticality	hospitals, government buildings, restoration time sensitive customers	5	Low	0
			High	1
Customer Impact	# of customers	15	<1,000	0
			>=1,000	1
Physical and Environmental Exposure *(Employees safety)*	Oil containment, blast wall, deluge system	5	Yes	0
			No	1
Location	Proximity to public places (school, residential, park	5	No	0
			Yes	1
Interconnection	Interconnection	50	Connected to more than 2	0
			Connected up to 2	0.5
			Connected to none	1
Obsolescence	No Spare Parts	10	None Available	0
			Some Available	1
PCB Content	PCB Content PPM	10	<2	0
			>=2	1

The table below shows examples of criticalities for three separate units.

	Example 1			Example 2			Example 3		
Criticality Factor	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**	**Values**	**CFS**	**CFS x WCF**
Load Criticality	Low	0	0	High	1	5	High	1	5
Customer Impact	500	0	0	2000	1	15	2000	1	15
Physical and Environmental Exposure	Yes	0	0	Yes	0	0	No	1	5
Location	No	0	0	No	0	0	Yes	1	5
Interconnection	Connected to more than 2	0	0	Connected to more than 2	0	0	No connections	1	50
Obsolescence	No spares available	0	0	No spares available	0	0	Spare parts available	1	20
PCB Content	PCB < 2 PPM	0	0	10 PPM	1	10	10 PPM	1	10
	Criticality Multiple		0	Criticality Multiple		0.35	Criticality Multiple		1
	Criticality		(1.43-1.11) *0 + 1.11 = **1.11**	**Criticality**		(1.43-1.05) *0.35 + 1.05 = **1.18**	**Criticality**		(1.43-1.05) *1 + 1.05 =**1.43**

As previously noted a unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one. The flagged for action plan for in service Substation Transformers was as follows:

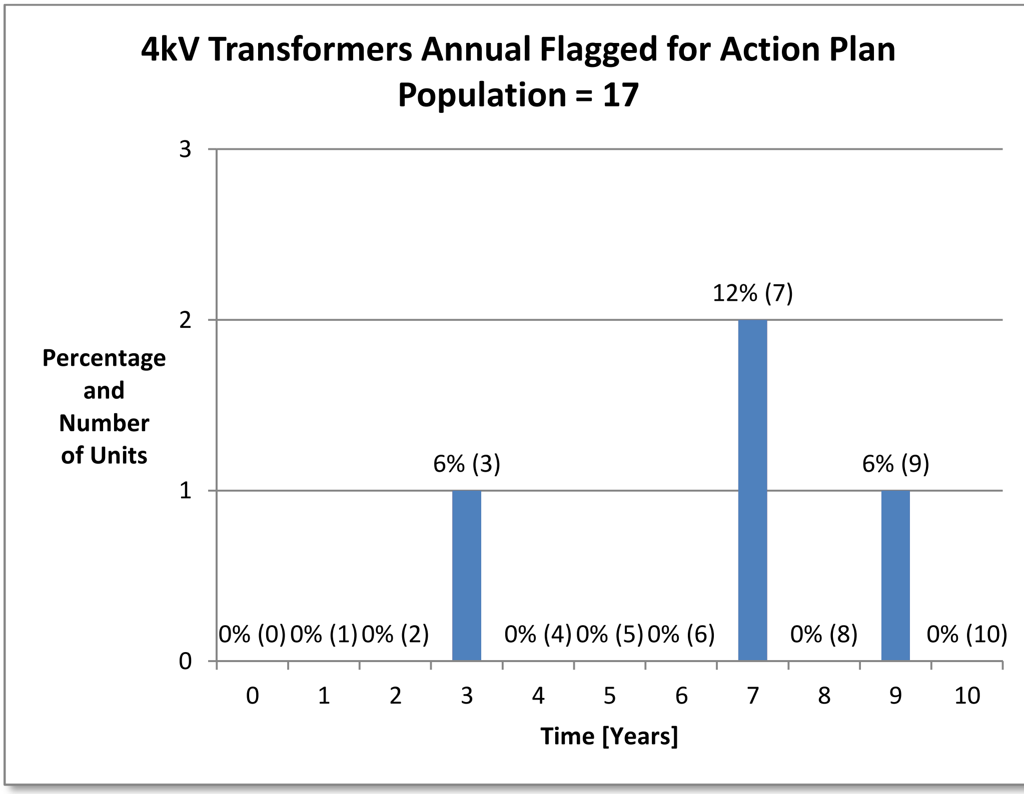

Figure 1-8 4kV Secondary Substation Transformers Risk Based Flagged for Action Plan

No 12kV Transformers are flagged for action in the next 10 years.

1.3 Summary of Results

A summary of all above results are tabulated in the table below.

Table 1-7 Transformers Results Summary

ID	Serial Number	Station Number	Location	Manufacturer	MVA	Primary Voltage (kV)	Secondary Voltage (kV)	Age	DAI	HI (Condition)	HI	HI Category	Flagged for Action Year	Station MVA	Total 4 kV Poles in Station	Average 4kV Poles based on MVA	Total 25 kV Poles in Station	Average 4kV Poles based on MVA
3T1	237994	3	STN #3 HARDISTY	GENERAL ELECTRIC	3	22	4	67	93%	99.0%	25.4%	Poor	3	7	245	105	3	1
3T2	239722	3	STN #3 HARDISTY	GENERAL ELECTRIC	4	22	4	63	93%	84.0%	61.5%	Fair	7	7	245	140	3	2
16T1	276459	16	STN#16 MACDONNEL	GENERAL ELECTRIC	4	23	4	62	100%	92.5%	68.7%	Fair	7	8	137	69	0	0
21T1	245193	21	STN 21 WINDEMERE	ENGLISH ELECTRIC	4	23	4	60	93%	84.2%	80.0%	Good	9	8	592	296	3	2
5T1	281875	5	STN 5 DONALD	GENERAL ELECTRIC	4	22	4	58	93%	100.0%	87.5%	Very Good	12	8	162	81	24	12
16T2	282816	16	STN#16 MACDONNEL	GENERAL ELECTRIC	4	23	4	57	93%	100.0%	90.2%	Very Good	12	8	137	69	0	0
4T1	282960	4	STN #4 VICKER	GENERAL ELECTRIC	4	22	4	57	93%	95.6%	90.2%	Very Good	13	4	203	203	0	0
21T2	290663	21	STN 21 WINDEMERE	WESTINGHOUSE	4	23	4	57	93%	99.2%	90.2%	Very Good	12	8	592	296	3	2
14T1	282815	14	STN#14 ALGOMA	GENERAL ELECTRIC	4	23	4	57	93%	98.7%	90.2%	Very Good	14	4	335	335	3	3
18T1	11117	18	BALSALM	FERRANTI PACKARD	6.667	23	12	56	93%	100.0%	92.4%	Very Good	13	13.334	0	0	842	421
11T1	11118	11	STN 11 HIGH ST	FERRANTI PACKARD	5	23	4	56	93%	97.5%	92.4%	Very Good	14	5	398	398	2	2
5T2	284751	5	STN 5 DONALD	GENERAL ELECTRIC	4	22	4	53	93%	100.0%	96.4%	Very Good	17	8	162	81	24	12
9T1	230831	9	STN 9 MOUNTDALE	MOLONEY ELECTRIC	4	22	4	50	93%	99.2%	98.3%	Very Good	20	4	207	207	0	0
15T1	WT15841	15	STN #15 GRENVILLE	PIONEER ELECTRIC	6.667	24	4	47	93%	99.9%	99.2%	Very Good	20+ years	6.667	496	496	1	1
12T1	WT15842	12	STN#12 CAMELOT	PIONEER ELECTRIC	6.667	24	4	47	93%	100.0%	99.2%	Very Good	20+ years	13.334	603	302	34	17
12T2	WT15843	12	STN#12 CAMELOT	PIONEER ELECTRIC	6.667	24	4	47	93%	100.0%	99.2%	Very Good	20+ years	13.334	603	302	34	17
23T1	255104	23	STN#23	MOLONEY ELECTRIC	6.667	24.94	12	44	93%	88.7%	88.7%	Very Good	20+ years	6.667	0	0	979	979
36T1B	29751	36	STN 36 MAPLEWARD	PIONEER ELECTRIC	2	22	12	48	93%	94.7%	94.7%	Very Good	20+ years	6	0	0	1703	568
36T1R	29754	36	STN #36 MAPLEWARD	PENNSYLVANIA TRANSFORMER	2	22	12	48	93%	94.7%	94.7%	Very Good	20+ years	6	0	0	1703	568
36T1W	29753	36	STN #36 MAPLEWARD	PIONEER ELECTRIC	2	22	12	48	93%	94.7%	94.7%	Very Good	20+ years	6	0	0	1703	568
Northwood	S391201	Northwood	NORTHWOOD PLAZA	PIONEER ELECTRIC	1.69	24.94	4	44	68%	100.0%	99.6%	Very Good	20+ years	1.69	0	0	0	0
18T2	255105	18	STN#18	MOLONEY ELECTRIC	6.667	24.94	4	44	93%	100.0%	99.6%	Very Good	20+ years	13.334	0	0	842	421
19T1	41171	19	STN 19 BROADWAY	MOLONEY ELECTRIC	6.667	24.94	12	36	93%	100.0%	100.0%	Very Good	20+ years	6.667	0	0	392	392

1.3 Data Assessment

Age, loading, oil quality and dissolved gas analysis tests were available for all Substation Transformers. The average DAI for this asset category is 93%, indicating that a majority of the assets have the above information.

Additional data that, if available in a useable format, can be incorporated into the assessment is shown below.

Table 1-8 Substation Transformers Data Gaps

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Power Dissipation Factor	Insulation	☆☆☆	Insulation	Doble Test Results	Tests
Bushing		☆	Bushing	condition of busing	Visual Inspection/ Corrective Maintenance Records
Cooling	Cooling	☆☆	Cooling oil	Abnormal oil flow	Visual Inspection / On-site Reading / Corrective Maintenance Records
				Abnormal oil pump motor	
			Cooling fan	Abnormal fan operation	
			Radiator	Plugged radiator	
			Valves	Broken valves	
			Transformer tank	High top oil temperature	
			Winding	High winding temperature	
Corrosion	Sealing and Connection	☆	Enclosure Condition	Signs of corrosion	Visual Inspection/ Corrective Maintenance Records
Paint		☆		Paint condition	
Oil Leak		☆		Signs of oil leak	
Connection		☆	Connections	Hot connection	
Grounding		☆	Grounding issues	Poor grounding	

2 Circuit Breakers

2.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

2.1.1 *Condition and Sub-Condition Parameters*

Table 2-1 Condition Parameter and Weights

Condition Parameter (CP)						Sub-Condition Parameter (SCP)						
n	Description	Weight (WCP)			De-Rating Multiplier (DR_CP)	m	Description	Weight (WSCP)			De-Rating Multiplier (DR_SCP)	SCP Criteria
		Oil	Air Blast	Vacuum				Oil	Air Blast	Vacuum		
1	Operating Mechanism	**14**	**14**	**7**	**1**	1	Internal Mechanism	**1**	**0**	**0**	**1**	Table 2-2
						2	Closing Mechanism	**1**	**1**	**1**	**1**	Table 2-2
						3	Trip Mechanism	**1**	**1**	**1**	**1**	Table 2-2
						4	Tolerance	**1**	**0**	**0**	1	Table 2-2
2	Contact Performance	**7**	**7**	**7**	**1**	1	Closing timing	**6**	**6**	**6**	**1**	Table 2-2
						2	Trip timing	**3**	**3**	**3**	**1**	Table 2-2
						3	Arcing contact	**3**	**3**	**0**	**1**	Table 2-2
						4	Main contact	**3**	**3**	**0**	**1**	Table 2-2
						5	Contact Resistance	**3**	**3**	**3**	**1**	Table 2-2
						6	Other	**1**	**1**	**1**	**1**	Table 2-2
3	Arc Extinction	**9**	**9**	**9**	**1**	1	Arc Chute	**0**	**2**	**0**	**1**	Table 2-2
						2	Heater	**1**	**0**	**0**	**1**	Table 2-2
						3	Tank Leak	**1**	**0**	**0**	**1**	Table 2-2
4	Insulation	**2**	**2**	**2**	**1**	1	Insulation	**1**	**1**	**1**	**1**	Table 2-2
5	Service Record	**5**	**5**	**5**	**1**	1	Operating Counter	**1**	**1**	**1**	**1**	Table 2-2
AGE Limiter							The final Health Index value will be limited by the asset age					Equation 9

2.1.2 *Condition Criteria*

Visual Inspection

Table 2-2 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Age Limiter

The final Health Index value is limited by the age of the asset shown below:

$$\text{Final Health Index} = \text{Minimum}\{ \text{HI}, S_f(t) \}$$

Equation 9

Where $S_f(t)$ is the survival function calculated as follows:

Assume that the failure rate Circuit Breakers exponentially increases with age and that the failure rate equation is as follows:

$$f(t) = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f(t) = 1 - \ P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 60 and 70 years the probability of failures (P_f) for Circuit Breakers are 20% and 95% respectively results in the survival curve shown below.

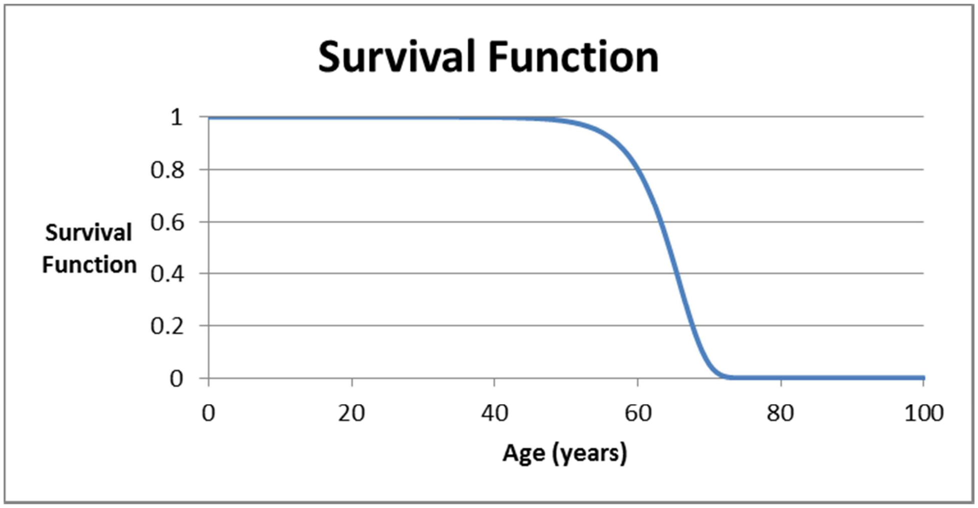

Figure 2-1 Circuit Breakers Survival Function

2.2 Age Distribution

The average age of the population was 56 years. The overwhelming majority, 94%, of the population is 45 years or older. The age distribution for this asset class was as follows:

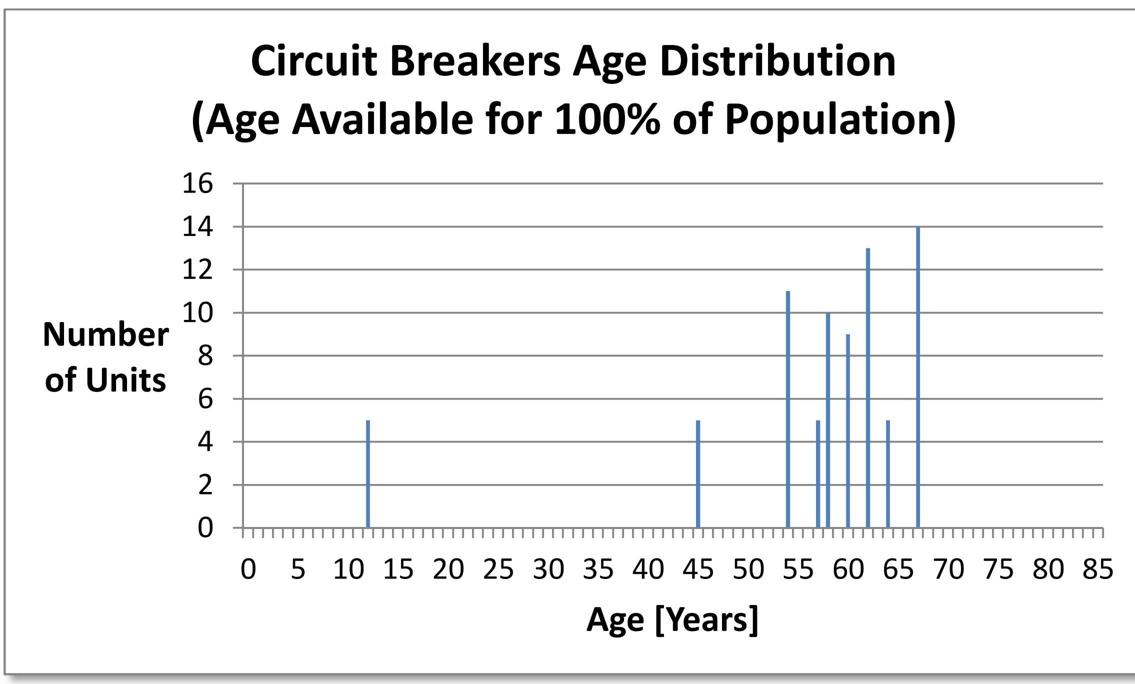

Figure 2-2 Circuit Breakers Age Distribution

2.3 Health Index Results

There are a total of 77 Circuit Breakers. All had sufficient data for Health Indexing.

The average Health Index for this asset group was 94%. Approximately 18% of the population was found to be in “poor” condition.

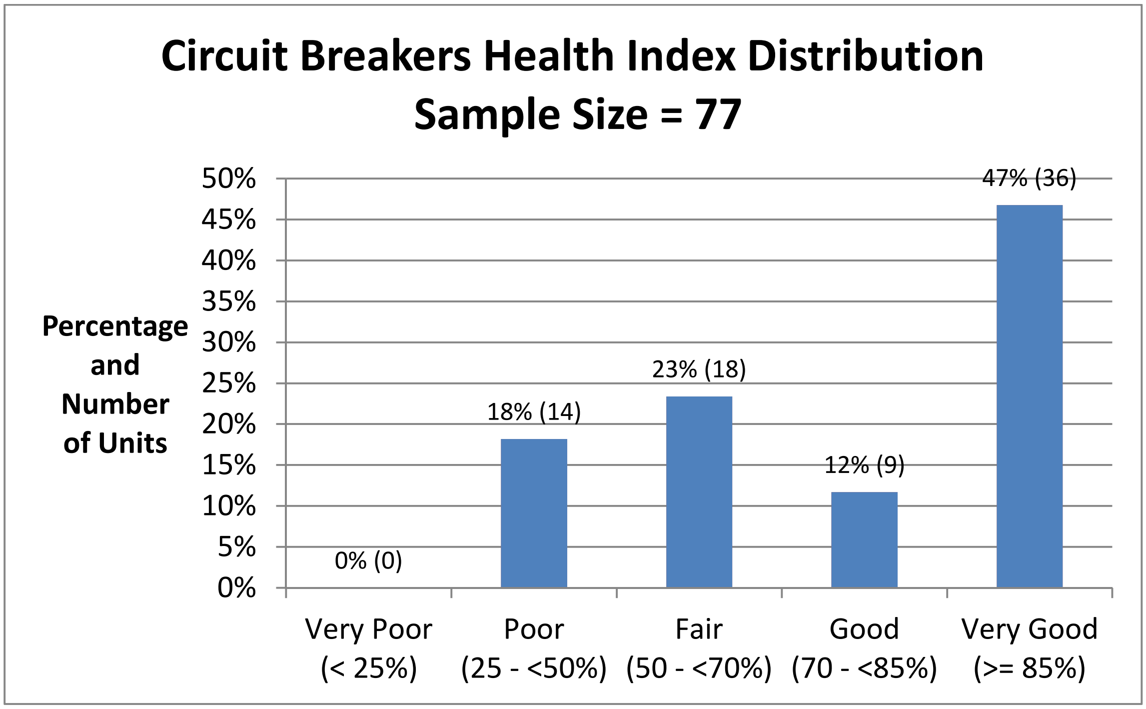

Figure 2-3 Circuit Breakers Health Index Distribution

2.4 Flagged for Action Plan

It is assumed that Circuit Breakers were proactively replaced.

A unit becomes a candidate for replacement when the product of its probability of failure and criticality is greater than or equal to one. All units are assumed to have equal criticalities, selected such that a unit with a probability of failure of 70% becomes a candidate for replacement. i.e. Criticality = 1.43.

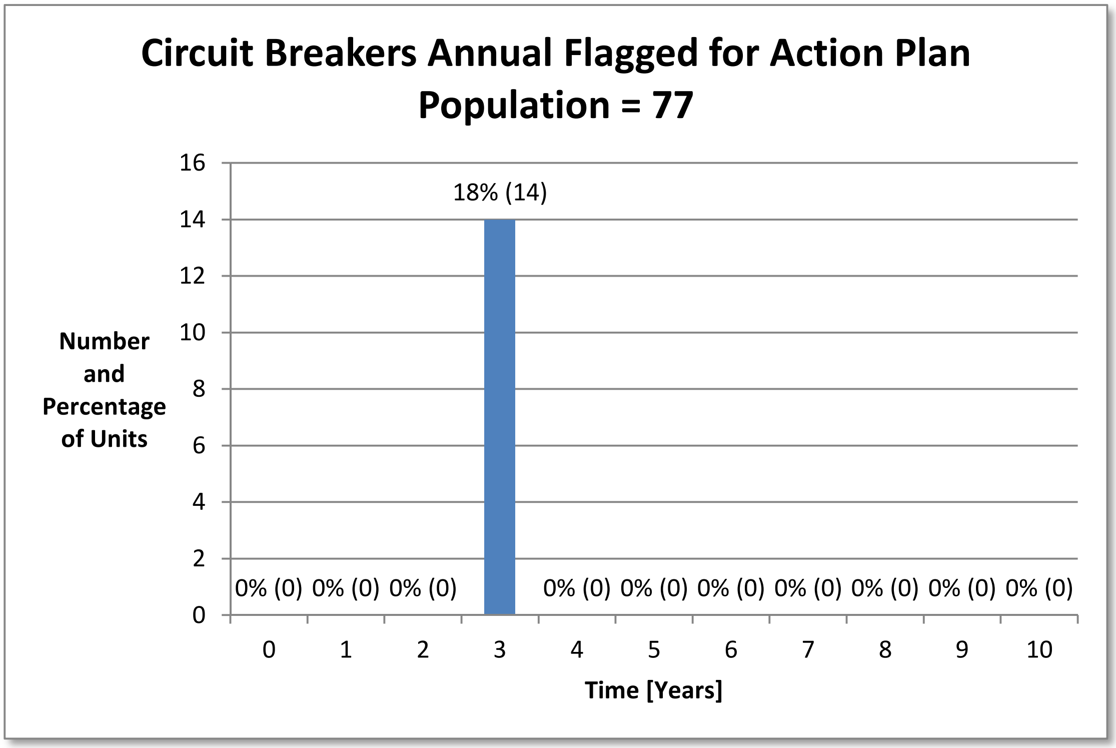

Figure 2-4 Circuit Breakers Risk Based Flagged for Action Plan

2.5 Summary of Results

A summary of all above results are tabulated in the table below.

Table 2-3 Circuit Breakers Results Summary

ID	Serial Number	Station	Location	Type	Manufacturer	Age	DAI	HI (Condition)	HI	HI Category	FFA Year
36557	36557	3	Hardisty	OCB	General Electric	67	53%	93.8%	25.4%	Poor	3
36558	36558	3	Hardisty	OCB	General Electric	67	77%	94.0%	25.4%	Poor	3
36559	36559	3	Hardisty	OCB	General Electric	67	77%	94.4%	25.4%	Poor	3
36560	36560	3	Hardisty	OCB	General Electric	67	77%	93.1%	25.4%	Poor	3
37979	37979	3	Hardisty	OCB	General Electric	67	73%	93.1%	25.4%	Poor	3
37980	37980	3	Hardisty	OCB	General Electric	67	3%	100.0%	25.4%	Poor	3
37981	37981	3	Hardisty	OCB	General Electric	67	3%	100.0%	25.4%	Poor	3
37982	37982	3	Hardisty	OCB	General Electric	67	3%	100.0%	25.4%	Poor	3
38306	38306	3	Hardisty	OCB	General Electric	67	3%	100.0%	25.4%	Poor	3
34912	34912	14	Algoma St.	OCB	General Electric	67	54%	95.3%	25.4%	Poor	3
34913	34913	14	Algoma St.	OCB	General Electric	67	57%	94.7%	25.4%	Poor	3
34914	34914	14	Algoma St.	OCB	General Electric	67	57%	94.7%	25.4%	Poor	3
34915	34915	14	Algoma St.	OCB	General Electric	67	56%	94.4%	25.4%	Poor	3
34916	34916	14	Algoma St.	OCB	General Electric	67	57%	94.7%	25.4%	Poor	3
85782	85782	15	Grenville St.	ACB	Pioneer Electric	64	81%	92.4%	53.3%	Fair	16
85783	85783	15	Grenville St.	ACB	Pioneer Electric	64	81%	92.0%	53.3%	Fair	16
85784	85784	15	Grenville St.	ACB	Pioneer Electric	64	81%	92.0%	53.3%	Fair	16
85785	85785	15	Grenville St.	ACB	Pioneer Electric	64	81%	92.0%	53.3%	Fair	16
85786	85786	15	Grenville St.	ACB	Pioneer Electric	64	81%	92.4%	53.3%	Fair	16
2-0444-1	2-0444-1	4	Vickers	ACB	Allis Chalmers	62	82%	92.0%	68.7%	Fair	20+ years
2-0444-2	2-0444-2	4	Vickers	ACB	Allis Chalmers	62	82%	92.0%	68.7%	Fair	20+ years
2-0444-3	2-0444-3	4	Vickers	ACB	Allis Chalmers	62	82%	92.0%	68.7%	Fair	20+ years
2-0444-4	2-0444-4	4	Vickers	ACB	Allis Chalmers	62	81%	92.0%	68.7%	Fair	20+ years
38923	38923	16	MacDonnell St.	OCB	General Electric	62	60%	95.1%	68.7%	Fair	20+ years
38924	38924	16	MacDonnell St.	OCB	General Electric	62	60%	95.1%	68.7%	Fair	20+ years
38925	38925	16	MacDonnell St.	OCB	General Electric	62	60%	94.5%	68.7%	Fair	20+ years
38926	38926	16	MacDonnell St.	OCB	General Electric	62	60%	94.9%	68.7%	Fair	20+ years
38927	38927	16	MacDonnell St.	OCB	General Electric	62	60%	94.9%	68.7%	Fair	20+ years
52775	52775	16	MacDonnell St.	OCB	General Electric	62	60%	95.1%	68.7%	Fair	20+ years
52776	52776	16	MacDonnell St.	OCB	General Electric	62	60%	94.4%	68.7%	Fair	20+ years
52777	52777	16	MacDonnell St.	OCB	General Electric	62	60%	94.8%	68.7%	Fair	20+ years
52781	52781	16	MacDonnell St.	OCB	General Electric	62	60%	95.1%	68.7%	Fair	20+ years
201097	201097	21	Windemere	OCB	English Electric	60	60%	94.4%	80.0%	Good	20+ years

ID	Serial Number	Station	Location	Type	Manufacturer	Age	DAI	HI (Condition)	HI	HI Category	FFA Year
201131	201131	21	Windemere	OCB	English Electric	60	60%	94.4%	80.0%	Good	20+ years
201133	201133	21	Windemere	OCB	English Electric	60	59%	94.0%	80.0%	Good	20+ years
231986	231986	21	Windemere	OCB	English Electric	60	59%	94.0%	80.0%	Good	20+ years
231987	231987	21	Windemere	OCB	English Electric	60	60%	93.5%	80.0%	Good	20+ years
52778	52778	21	Windemere	OCB	General Electric	60	50%	96.9%	80.0%	Good	20+ years
52782	52782	21	Windemere	OCB	General Electric	60	60%	95.1%	80.0%	Good	20+ years
52784	52784	21	Windemere	OCB	General Electric	60	60%	95.1%	80.0%	Good	20+ years
52785	52785	21	Windemere	OCB	General Electric	60	60%	95.1%	80.0%	Good	20+ years
51854	51854	5	Donald	OCB	General Electric	58	57%	94.4%	87.5%	Very Good	20+ years
51853	51853	5	Donald	OCB	General Electric	58	57%	94.4%	87.5%	Very Good	20+ years
51855	51855	5	Donald	OCB	General Electric	58	57%	94.4%	87.5%	Very Good	20+ years
51856	51856	5	Donald	OCB	General Electric	58	59%	94.1%	87.5%	Very Good	20+ years
51857	51857	5	Donald	OCB	General Electric	58	54%	94.3%	87.5%	Very Good	20+ years
55979	55979	5	Donald	OCB	General Electric	58	60%	93.5%	87.5%	Very Good	20+ years
55980	55980	5	Donald	OCB	General Electric	58	44%	92.7%	87.5%	Very Good	20+ years
55981	55981	5	Donald	OCB	General Electric	58	60%	93.5%	87.5%	Very Good	20+ years
55982	55982	5	Donald	OCB	General Electric	58	60%	93.5%	87.5%	Very Good	20+ years
55983	55983	5	Donald	OCB	General Electric	58	51%	93.6%	87.5%	Very Good	20+ years
52774	52774	18	Balsam St.	OCB	General Electric	57	60%	93.6%	90.2%	Very Good	20+ years
52779	52779	18	Balsam St.	OCB	General Electric	57	60%	94.5%	90.2%	Very Good	20+ years
52780	52780	18	Balsam St.	OCB	General Electric	57	60%	94.4%	90.2%	Very Good	20+ years
52783	52783	18	Balsam St.	OCB	General Electric	57	60%	95.1%	90.2%	Very Good	20+ years
52786	52786	18	Balsam St.	OCB	General Electric	57	60%	94.4%	90.2%	Very Good	20+ years
55560	55560	12	Camelot St.	ACB	General Electric	54	81%	90.6%	90.6%	Very Good	20+ years
55565	55565	12	Camelot St.	ACB	General Electric	54	81%	91.1%	91.1%	Very Good	20+ years
W2090-5	W2090-5	9	Mountdale Ave.	ACB	Pioneer Electric	45	81%	91.2%	91.2%	Very Good	20+ years
55561	55561	12	Camelot St.	ACB	General Electric	54	81%	91.2%	91.2%	Very Good	20+ years
55563	55563	12	Camelot St.	ACB	General Electric	54	81%	91.2%	91.2%	Very Good	20+ years
55570	55570	12	Camelot St.	ACB	General Electric	54	81%	91.2%	91.2%	Very Good	20+ years

ID	Serial Number	Station	Location	Type	Manufacturer	Age	DAI	HI (Condition)	HI	HI Category	FFA Year
55559	55559	12	Camelot St.	ACB	General Electric	54	81%	91.7%	91.7%	Very Good	20+ years
55562	55562	12	Camelot St.	ACB	General Electric	54	81%	91.7%	91.7%	Very Good	20+ years
W2090-4	W2090-4	9	Mountdale Ave.	ACB	Pioneer Electric	45	81%	92.4%	92.4%	Very Good	20+ years
55564	55564	12	Camelot St.	ACB	General Electric	54	81%	92.9%	92.9%	Very Good	20+ years
55566	55566	12	Camelot St.	ACB	General Electric	54	3%	100.0%	95.4%	Very Good	20+ years
55567 (SPARE)	55567 (SPARE)	12	Camelot St.	ACB	General Electric	54	3%	100.0%	95.4%	Very Good	20+ years
55569	55569	12	Camelot St.	ACB	General Electric	54	3%	100.0%	95.4%	Very Good	20+ years
W2090-1	W2090-1	9	Mountdale Ave.	ACB	Pioneer Electric	45	81%	92.5%	92.5%	Very Good	20+ years
W2090-2	W2090-2	9	Mountdale Ave.	ACB	Pioneer Electric	45	81%	92.9%	92.9%	Very Good	20+ years
W2090-3	W2090-3	9	Mountdale Ave.	ACB	Pioneer Electric	45	81%	92.9%	92.9%	Very Good	20+ years
1742876	1742876	11	High St.	VAC	Square D	12	61%	97.3%	97.3%	Very Good	20+ years
1742877	1742877	11	High St.	VAC	Square D	12	61%	97.3%	97.3%	Very Good	20+ years
1742875	1742875	11	High St.	VAC	Square D	12	61%	97.9%	97.9%	Very Good	20+ years
1742878	1742878	11	High St.	VAC	Square D	12	61%	97.9%	97.9%	Very Good	20+ years
1742879	1742879	11	High St.	VAC	Square D	12	61%	97.9%	97.9%	Very Good	20+ years

2.6 Data Analysis

For circuit breakers, age and maintenance reports that had information on the following were available: internal, closing, trip mechanisms; tolerance; close and trip timing; contacts; arc chute (Air Blast), heater and tank leak (oil); Insulation. The DAI for this asset group, however, is only 61%. Efforts should be made to ensure that the information is available for all breakers. Data that would be helpful include the actual operation counter and fault counter and fault level interrupted.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Total Operations Counts	Contact Performance	★★	Contact	Total number of operations	On-Site Reading
Fault Operations Counts		★★		Total number of fault operations	
Fault Level Interrupted		★★		Fault levels interrupted	Operation Records

3 Wood Poles

3.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

3.1.1 *Condition and Sub-Condition Parameters*

Table 3-1 Condition Parameter and Weights

<table>
<tr><th colspan="4">Condition Parameter (CP)</th><th colspan="5">Sub-Condition Parameter (SCP)</th></tr>
<tr><th>n</th><th>Description</th><th>Weight (WCP)</th><th>De-Rating Multiplier (DR_CP)</th><th>m</th><th>Description</th><th>Weight (WSCP)</th><th>De-Rating Multiplier (DR_SCP)</th><th>SCP Criteria</th></tr>
<tr><td>1</td><td>Pole Strength</td><td>0*</td><td>1</td><td>1</td><td>Pole Strength</td><td>0*</td><td>1</td><td>Based on test results</td></tr>
<tr><td rowspan="4">2</td><td rowspan="4">Physical Condition</td><td rowspan="4">0*</td><td rowspan="4">1</td><td>1</td><td>Rot</td><td>0*</td><td>1</td><td>Table 3-2</td></tr>
<tr><td>2</td><td>Damage</td><td>0*</td><td>1</td><td>Table 3-2</td></tr>
<tr><td>3</td><td>Animal Damage</td><td>0*</td><td>1</td><td>Table 3-2</td></tr>
<tr><td>4</td><td>Lean</td><td>0*</td><td>1</td><td>Table 3-2</td></tr>
<tr><td rowspan="3">3</td><td rowspan="3">Accessories</td><td rowspan="3">0*</td><td rowspan="3">1</td><td>1</td><td>Guy Wire & Anchor</td><td>0*</td><td>1</td><td>Table 3-2</td></tr>
<tr><td>2</td><td>Ground Wire</td><td>0*</td><td>1</td><td>Table 3-2</td></tr>
<tr><td>3</td><td>Crossarm</td><td>0*</td><td>1</td><td>Table 3-2</td></tr>
<tr><td rowspan="2">4</td><td rowspan="2">Service Record</td><td rowspan="2">1</td><td rowspan="2">1</td><td>1</td><td>Age</td><td>1</td><td>1</td><td>Figure 3-1
Figure 3-2</td></tr>
<tr><td>2</td><td>Risk Rating</td><td>4</td><td>1</td><td>Table 3-3</td></tr>
<tr><td colspan="4">AGE Limiter</td><td colspan="4">The final Health Index value will be limited by the asset age</td><td>Equation 10</td></tr>
<tr><td colspan="9">*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.</td></tr>
</table>

3.1.2 *Condition Criteria*

Visual Inspection

Table 3-2 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Risk Rating

Table 3-3 Risk Rating Criteria

Score	TBH Risk Rating Description
0	Red
1	Orange
2	Yellow
3	Purple
4	Blue

Age

Assume that the failure rate Wood Poles exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 60 and 75 years the probability of failures (P_f) for this asset are 20% and 95% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

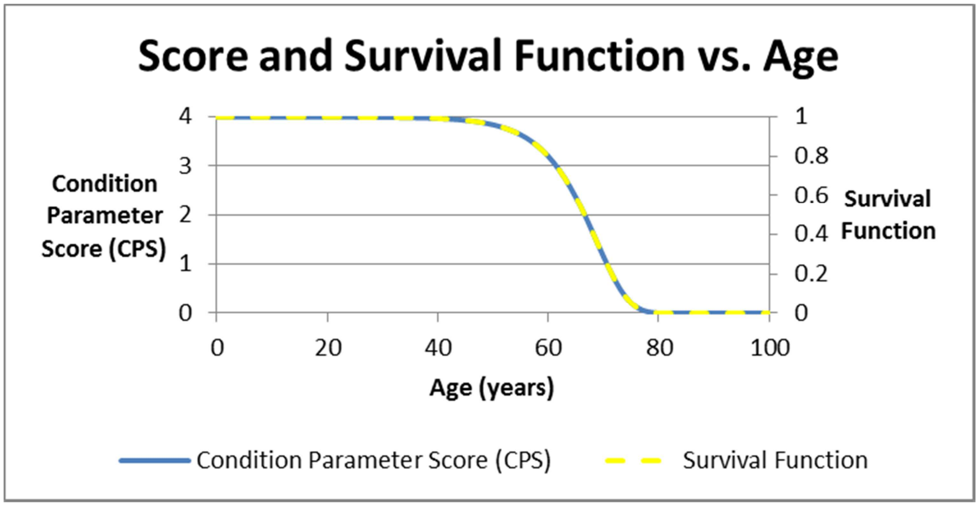

Figure 3-1 Wood Poles Age Criteria

Painted poles and poles in poor soil are assumed to have a shorter lifespan, i.e. the ages of 45 and 60 years correspond to 20% and 95% probability of failure respectively.

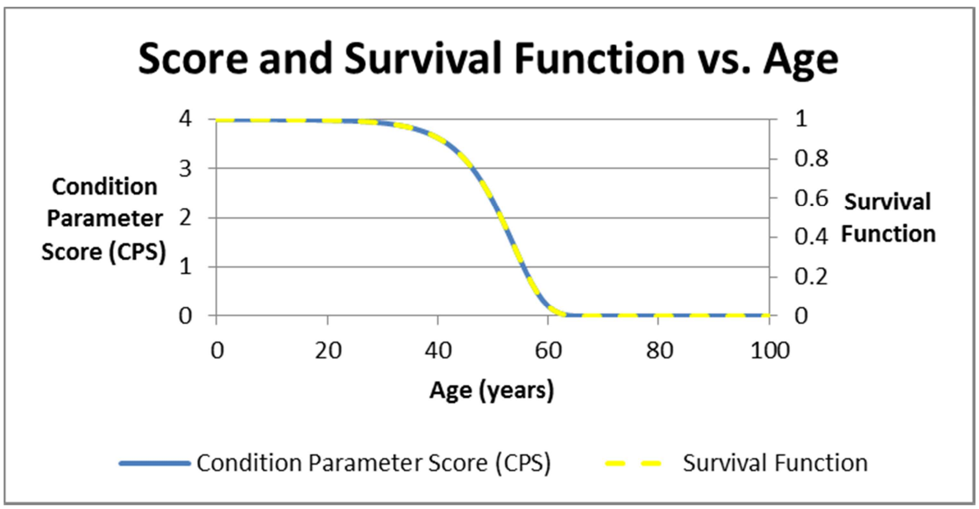

Figure 3-2 Painted Wood Poles and Wood Poles in Poor Soil Age Criteria

Age Limiter

The final Health Index value is limited by the age of the asset shown below:

$$\text{Final Health Index} = \text{Minimum}\{ \text{HI}, S_f(t) \} \quad \textbf{Equation 10}$$

Where $S_f(t)$ is the survival function shown in Figure 3-1 and Figure 3-2.

3.2 Age Distribution

The average age of all poles was 26 years.

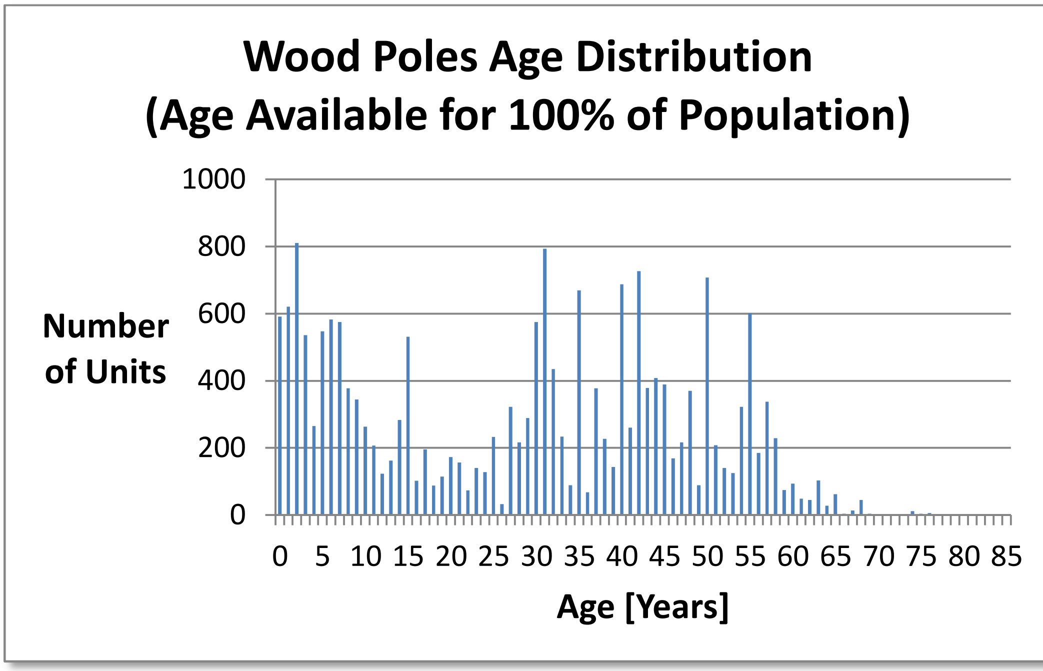

Figure 3-3 ALL Wood Poles Age Distribution

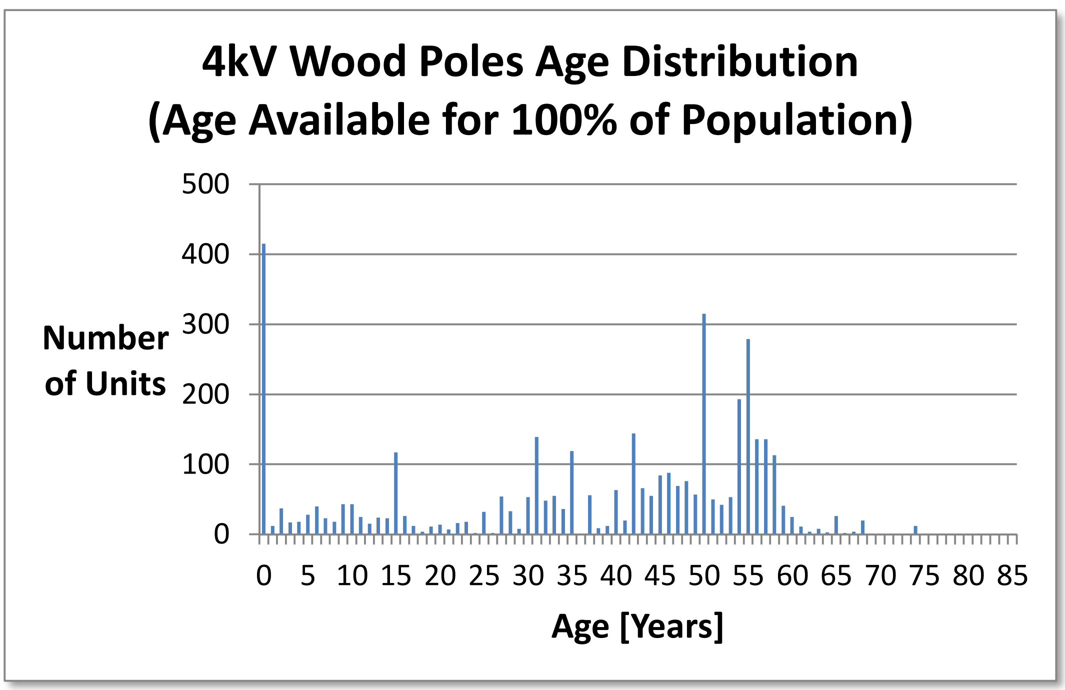

Figure 3-4 4kV Wood Poles Age Distribution

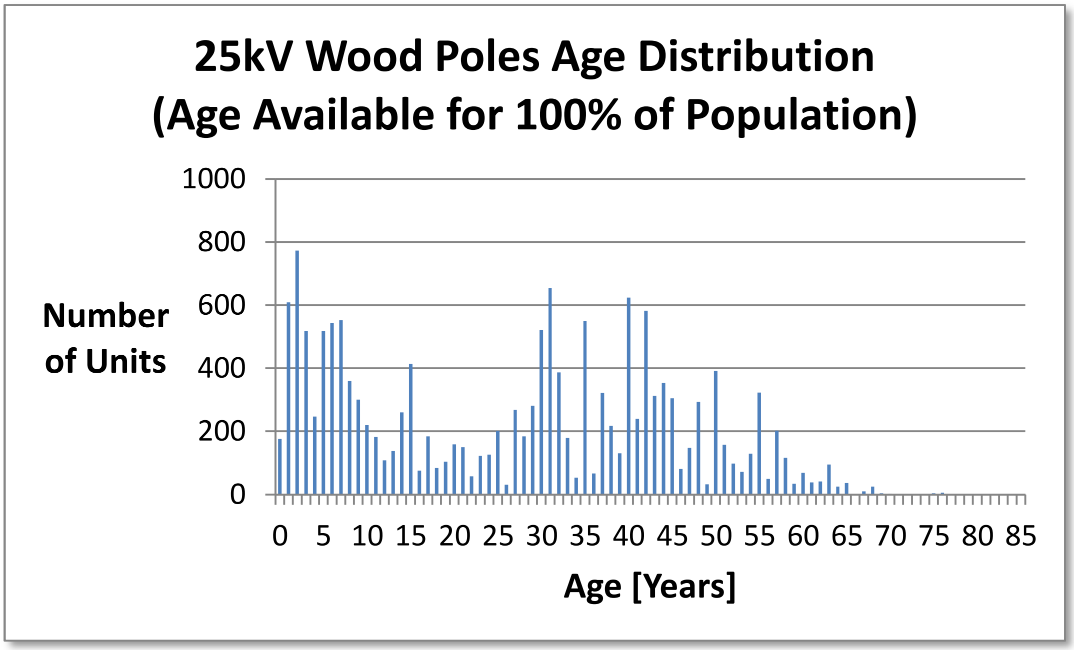

Figure 3-5 25kV Wood Poles Age Distribution

3.3 Health Index Results

There are a total of 19813 Wood Poles. Of these, all had sufficient data for Health Indexing. Approximately 10% of all poles are in poor or very poor condition.

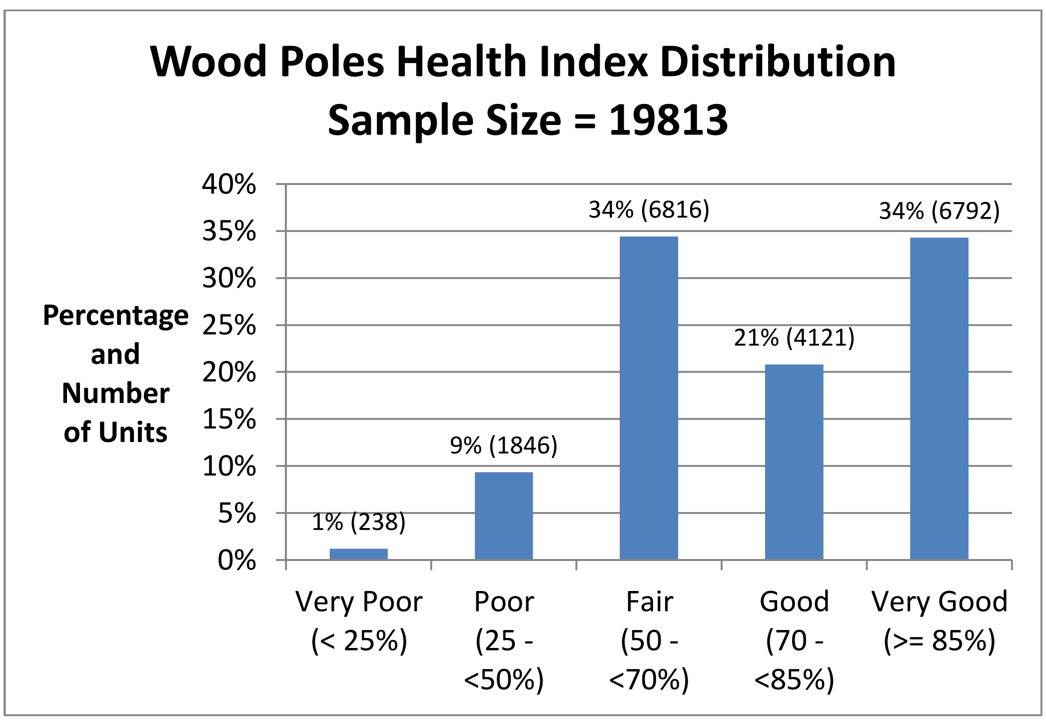

Figure 3-6 ALL Wood Poles Health Index Distribution

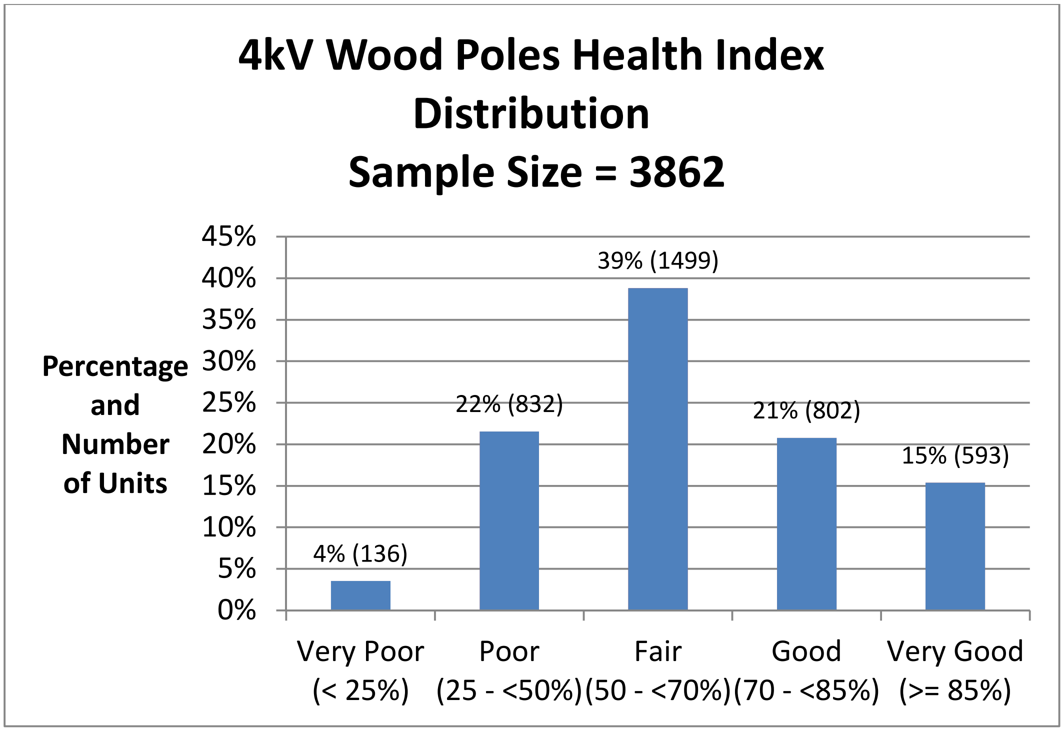

Figure 3-7 4kV Wood Poles Health Index Distribution

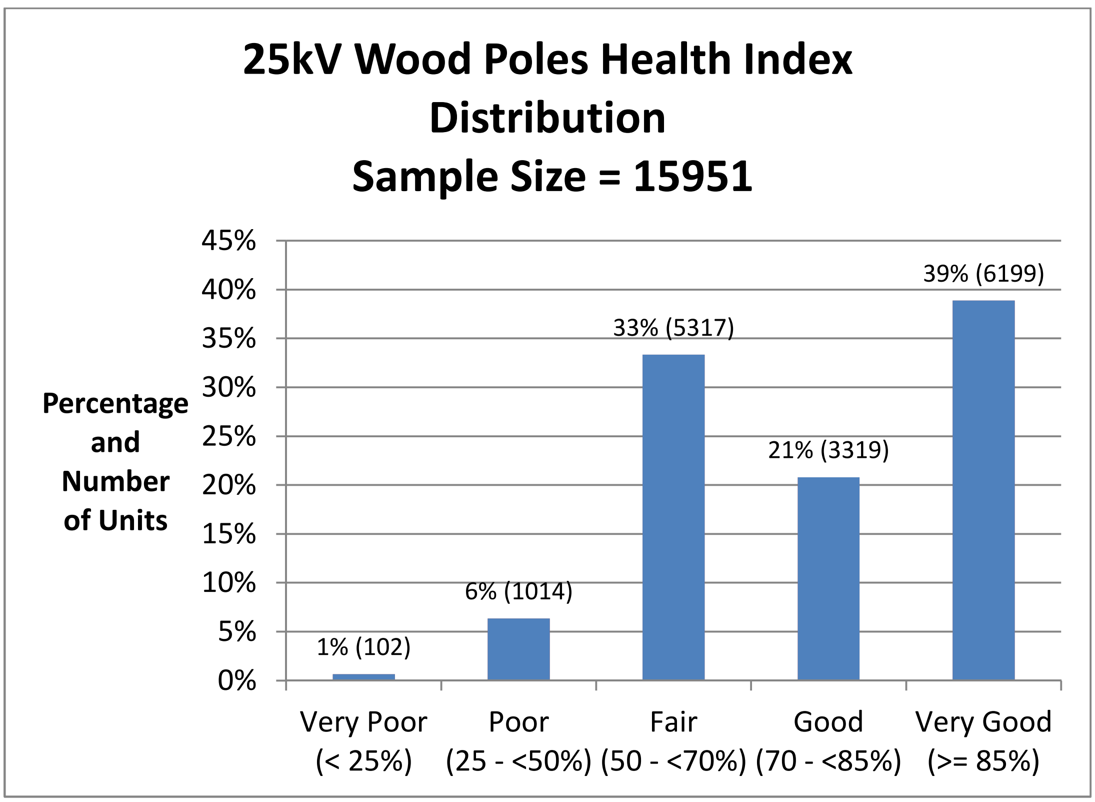

Figure 3-8 25kV Wood Poles Health Index Distribution

3.4 Flagged for Action Plan

The flagged for action plan are as follows:

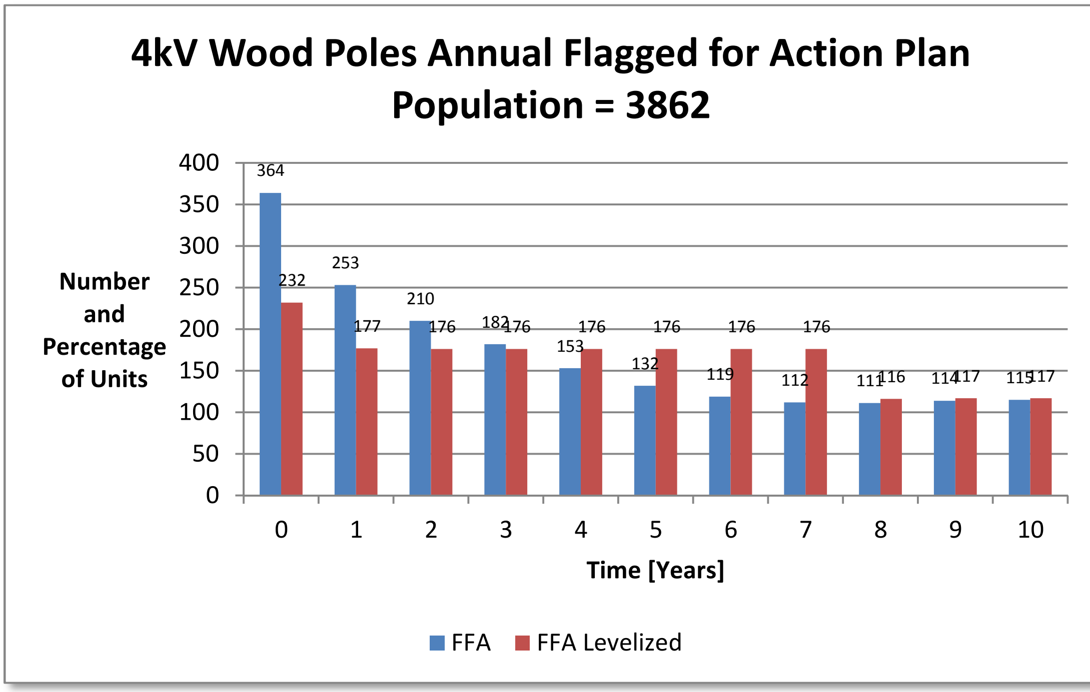

Figure 3-9 4kV Wood Poles Flagged for Action Plan

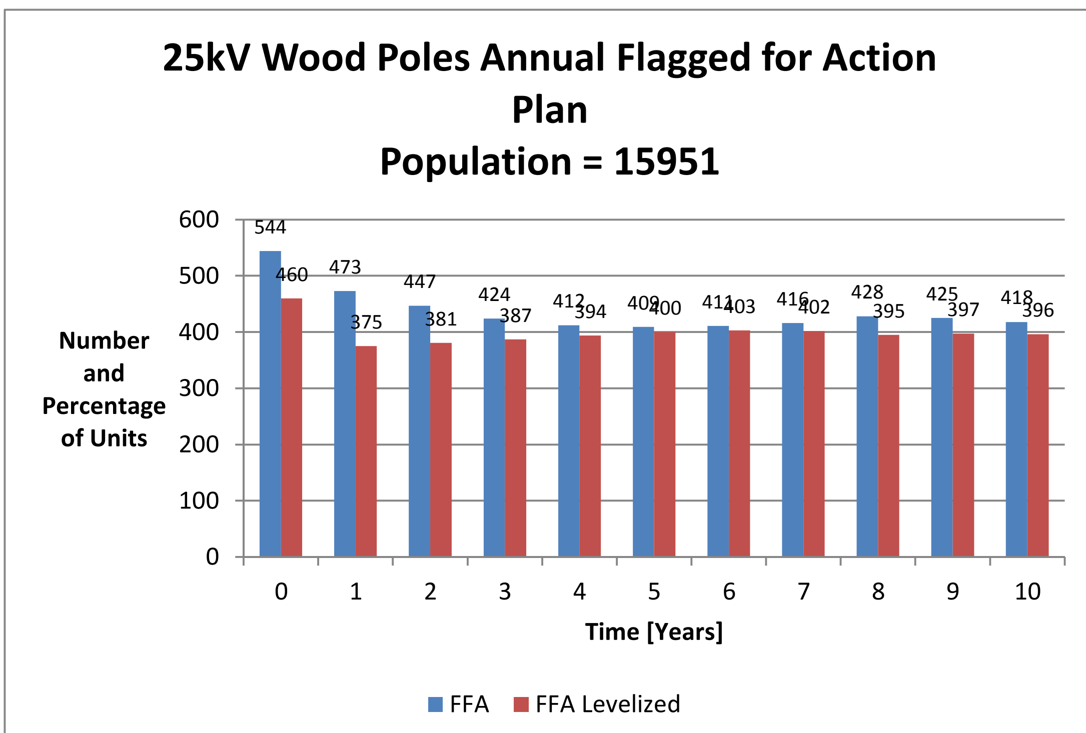

Figure 3-10 25kV Wood Poles Flagged for Action Plan

3.5 Data Analysis

Age and overall risk rating based on inspection records were available for wood poles. The DAI was 100% meaning all poles had the above information. Data gaps include more detailed inspection records and strength tests that give an objective assessment of the condition of wood poles.

Data Gap (Sub-Condition Parameter)	Parent Condition Parameter	Priority	Object or Component Addressed	Description	Source of Data
Pole Strength	Pole Strength	☆☆☆	Pole Circumference	Ratio of actual circumference over the original circumference	On-site Testing
			Pole Strength	Ratio of actual strength (psi) over the design strength (psi) Primarily used for wood poles, however core sample tests may be possible for concrete poles	
Rot	Physical Condition	☆☆	Pole	Top feathering	Visual inspection/ Corrective Maintenance
Animal Damage				Woodpecker, ant, or other type of animal damage	
Separation				Pole breaking apart	
Voids / Holes				Hole due to degradation	
Cracks				Surface crack due to deterioration or fatigue	
Guy Wire and Anchor	Accessories	☆	Pole Accessories	Condition of guy wire	Visual inspection/ Corrective Maintenance

Cross-Arm		✮	Pole Accessories	Condition of cross arm	Visual inspection/ Corrective Maintenance
Ground Wire		✮	Pole Accessories	Condition of ground wire	Visual inspection/ Corrective Maintenance

4 Pad Mounted Transformers

4.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

4.1.1 *Condition and Sub-Condition Parameters*

Table 4-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	**Description**	**Weight (WCP)**	**De-Rating Multiplier (DR_CP)**	**m**	**Description**	**Weight (WSCP)**	**De-Rating Multiplier (DR_SCP)**	**SCP Criteria**
1	Physical Condition	1	1	1	Enclosure Damage	5	1	Table 4-2
				2	Access	0*	1	Table 4-2
				3	Base	2	1	Table 4-2
2	Connection and Insulation	1	1	1	Oil Leak	1	1	Table 4-2
				2	Connection	0*	1	Table 4-2
3	Service Record	3	1	1	Hazardous Condition	4	1	Table 4-2
				2	Age	3	1	Figure 4-1
				3	Loading	0*	1	Table 4-3
Overall HI De-Rating Multiplier (DR)				PCB and/or Leaker and/or Hazardous Condition				Table 4-4
*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.								

4.1.2 *Condition Criteria*

<u>Visual Inspection</u>

Table 4-2 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Loading History

Table 4-3 Loading History

Data: S1, S2, S3, …, SN recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

Age

Assume that the failure rate Pad Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 35 and 45 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

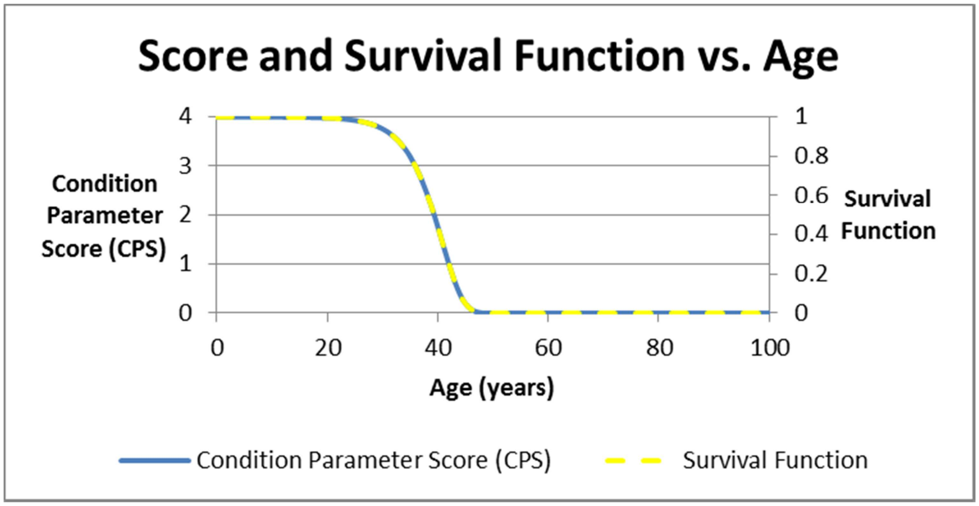

Figure 4-1 Pad Mounted Transformers Age Criteria

De-Rating (DR)

A de-rating multiplier will be applied to units that have a certain level of PCB and/or are leakers.

Table 4-4 De-Rating Criteria

Condition		De-Rating Multiplier (DR)
If	(PCB > 2 ppm) AND (Leaker)	0.1
Else if	PCB >= 2 ppm	0.25
Else if	Hazardous Condition	0.5
Else		1

4.2 Age Distribution

The average age of all single phase units was 25 years.

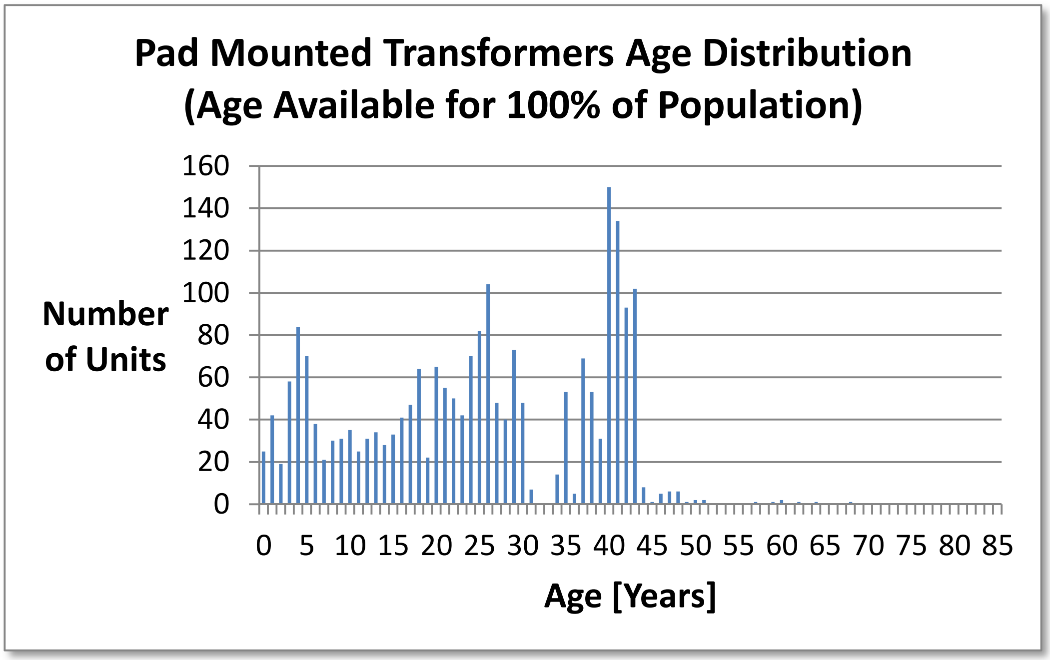

Figure 4-2 Pad Mounted Transformers Age Distribution

4.3 Health Index Results

There are a total of 2206 Pad Mounted Transformers at TBH. Of these, all had sufficient data for Health Indexing. A total of 10% were found to be in poor or very poor condition. These include units that have PCBs and/or are leakers.

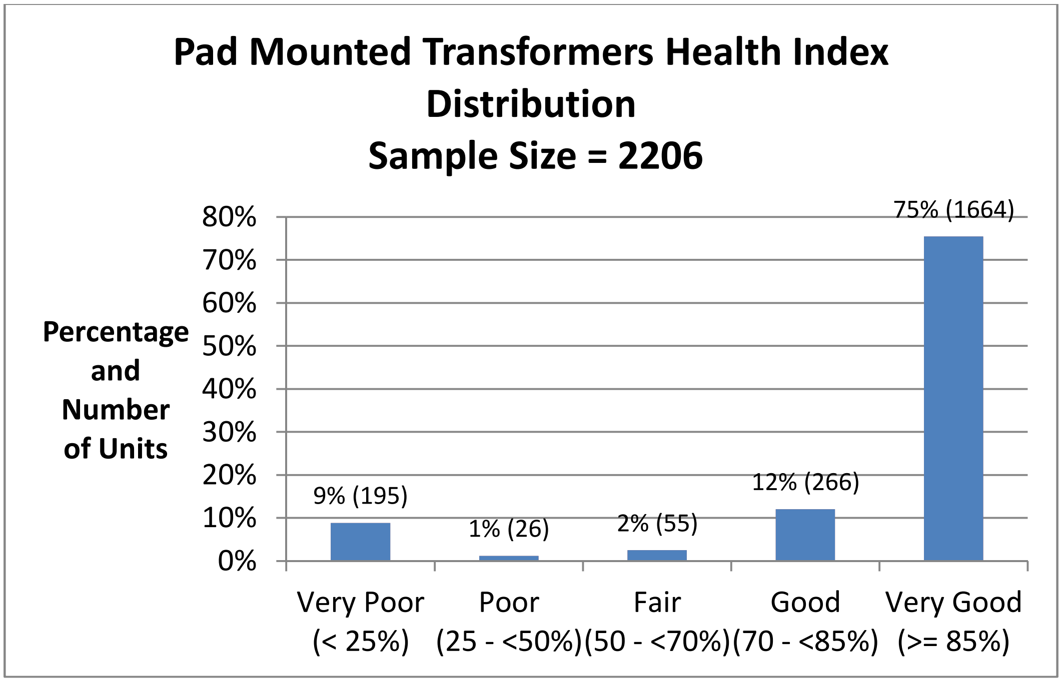

Figure 4-3 Pad Mounted Transformers Health Index Distribution

4.4 Flagged for Action Plan

As it is assumed that Pad Mounted Transformers were reactively replaced, the flagged for action plan was based on the asset failure rate.

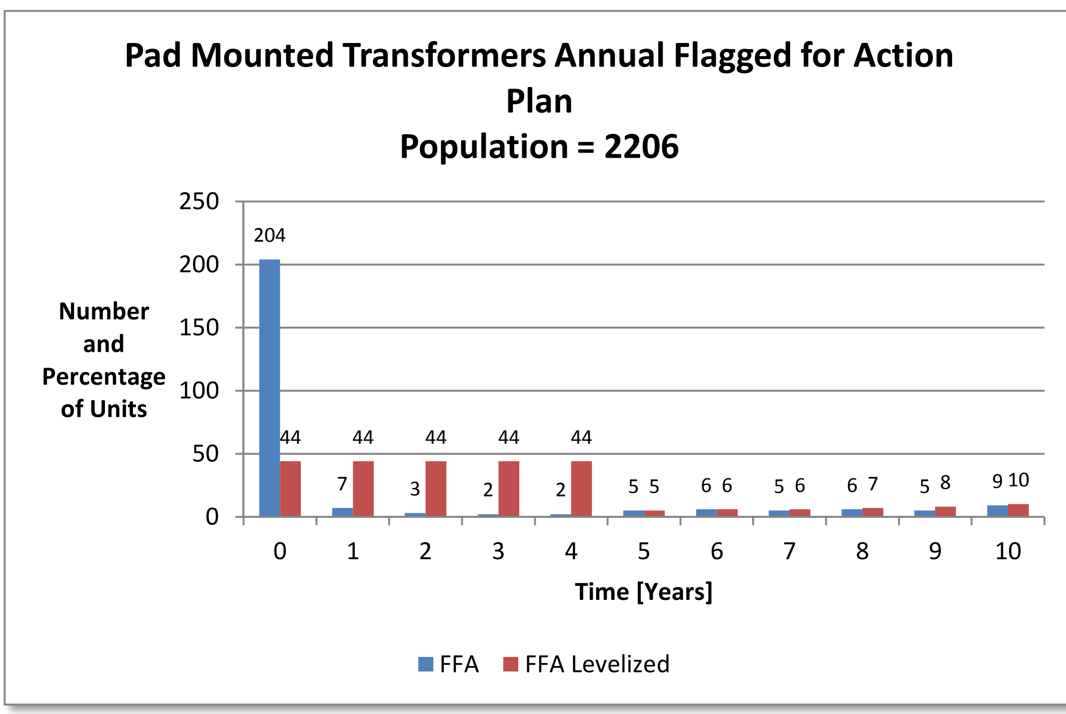

Figure 4-4 Pad Mounted Transformers Flagged for Action Plan

4.5 Data Analysis

Age, PCB content, and inspection records that provide information on transformer base, enclosure, leaks, and overall hazard condition were available for pad mounted transformers. The DAI was 85% meaning that a majority of all units had the above information. Loading and inspection/corrective maintenance information related to the connections (elbows/inserts) would be helpful for future assessments.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Transformer Access	Physical Condition	☆	Transformer	Accessibility	Visual inspection/ Corrective Maintenance
Connection	Connection & Insulation	☆ ☆	Elbows and Inserts	Condition of elbows/inserts	Visual inspection/ Corrective Maintenance
Loading	Service Record	☆ ☆	Transformer load	Monthly 15 min peak load throughout years	Operation record

5 Pole Mounted Transformers

5.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

5.1.1 *Condition and Sub-Condition Parameters*

Table 5-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	**Description**	**Weight (WCP)**	**De-Rating Multiplier (DR_CP)**	**m**	**Description**	**Weight (WSCP)**	**De-Rating Multiplier (DR_SCP)**	**SCP Criteria**
1	Physical Condition	0*	1	1	Tank Corrosion	0*	1	Table 5-2
2	Connection and Insulation	0*	1	1	Oil Leak	0*	1	Table 5-2
				2	Connection	0*	1	Table 5-2
3	Service Record	4	1	1	Overall	0*	1	Table 5-2
				2	Age	1	1	Figure 5-1
				4	Loading	0*	1	Table 5-3
Overall HI De-Rating Multiplier (DR)				PCB				Table 5-4
*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.								

5.1.2 *Condition Criteria*

<u>Visual Inspection</u>

Table 5-2 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Loading History

Table 5-3 Loading History

Data: S1, S2, S3, …, SN recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

Age

Assume that the failure rate Pole Mounted Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 50 and 65 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

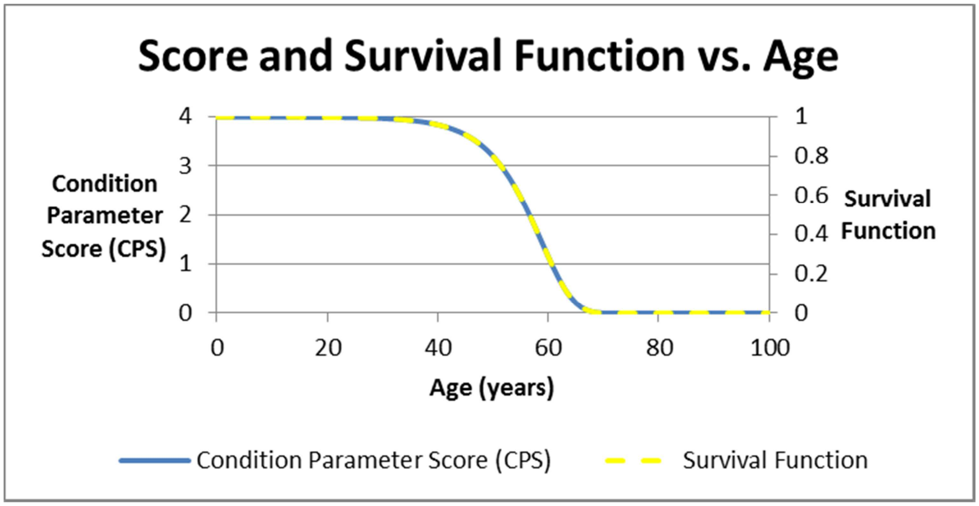

Figure 5-1 Pole Mounted Transformers Age Criteria

De-Rating (DR)

A de-rating multiplier will be applied to units that have a certain level of PCB and/or are leakers.

Table 5-4 De-Rating Criteria

Condition		De-Rating Multiplier (DR)
If	PCB > 2 ppm	0.25
Else		1

5.2 Age Distribution

The average age of is 29 years.

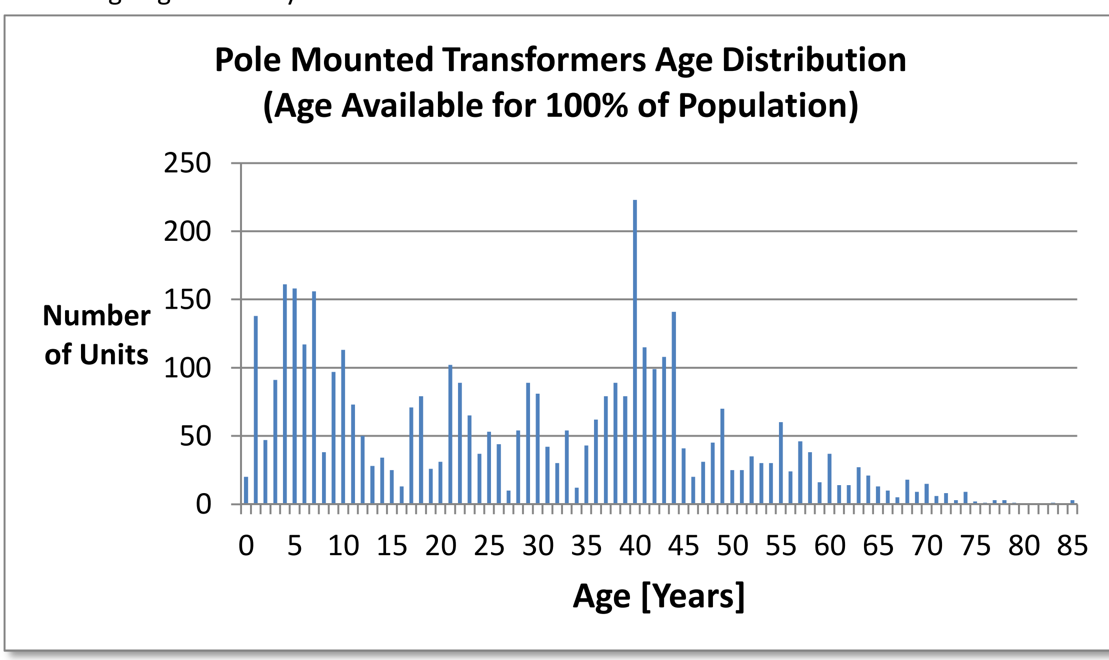

Figure 5-2 Pole Mounted Transformers Age Distribution

5.3 Health Index Results

There are 4143 Pole Mounted Transformers at TBH. Of these, all had sufficient data for Health Indexing.

The average Health Index for this asset group was 81. Approximately 20% of the population was found to be in “poor” or “very poor” condition. These include units that have PCBs.

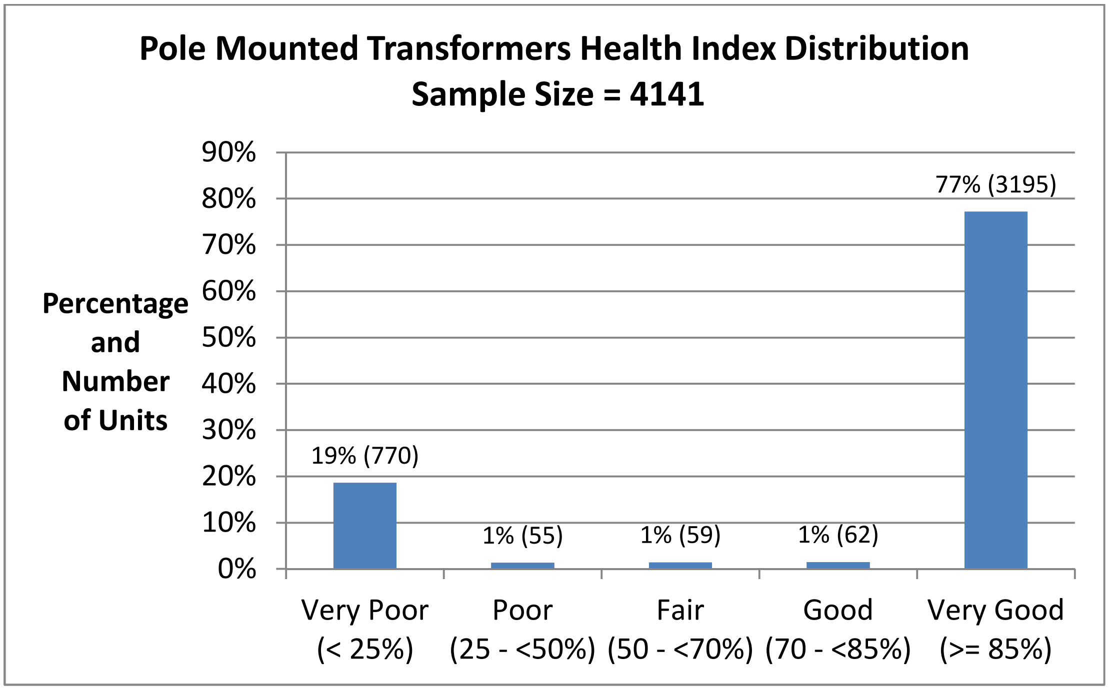

Figure 5-3 ALL Pole Mounted Transformers Health Index Distribution

5.4 Flagged for Action Plan

As it is assumed that Pole Mounted Transformers were reactively replaced, the flagged for action plan was based on the asset failure rate. The flagged for action plan for Pole Mounted Transformers is as follows:

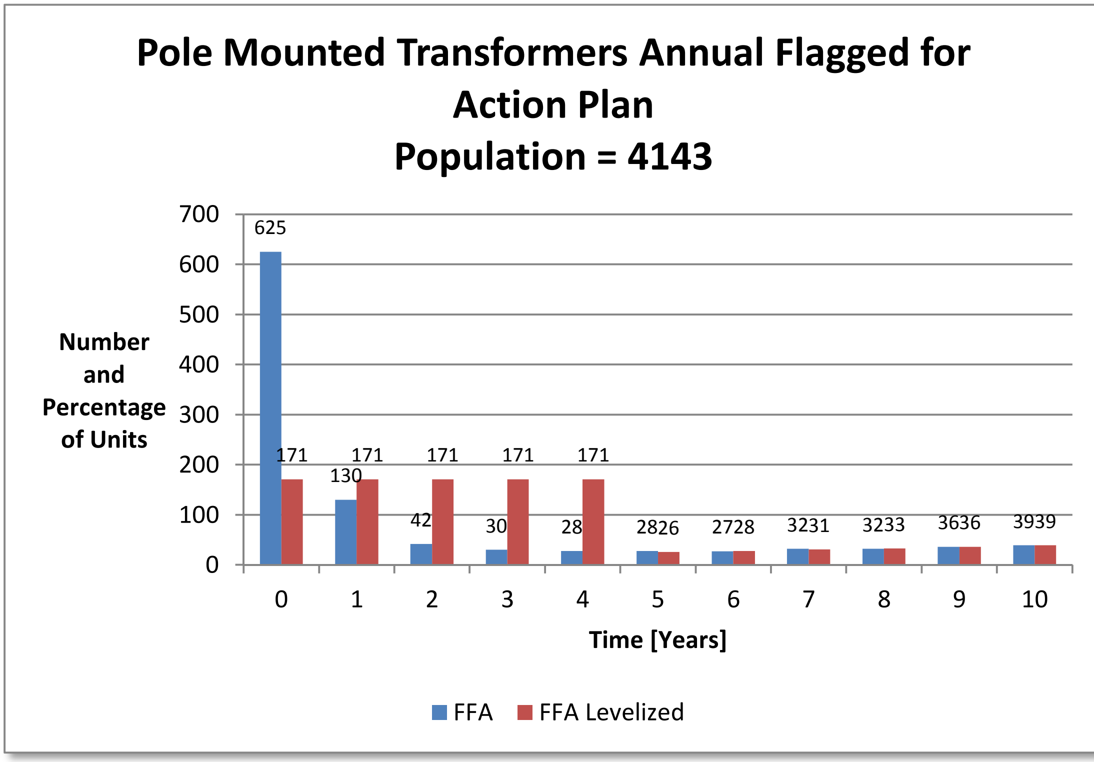

Figure 5-4 Pole Mounted Transformers Flagged for Action Plan

5.5 Data Analysis

The data available for Pole Mounted Transformers were age and PCB content. The average DAI was 100%. The data gaps, which are primarily from inspections, are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	☆☆	Transformer oil tank	Tank surface rust or deterioration due to environmental factors	Visual inspection/ Corrective Maintenance
Oil Leak	Connection & Insulation	☆☆☆	Transformer tank	Leakage	Visual inspection/ Corrective Maintenance
Connection		☆☆	Transformer connection	Poor connection	Visual inspection/ Corrective Maintenance
Overall	Service Record	☆	Transformer	General status evaluation based on routine operation and inspection	Visual inspection/ Corrective Maintenance
Loading		☆☆	Transformer load	Monthly 15 min peak load throughout years	Operation record

6 Vault Transformers

6.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

6.1.1 *Condition and Sub-Condition Parameters*

Table 6-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	**Description**	**Weight (WCP)**	**De-Rating Multiplier (DR_CP)**	**m**	**Description**	**Weight (WSCP)**	**De-Rating Multiplier (DR_SCP)**	**SCP Criteria**
1	Physical Condition	0*	1	1	Enclosure	0*	1	Table 6-2
				2	Access	0*	1	Table 6-2
2	Connection and Insulation	0*	1	1	Oil Leak	0*	1	Table 6-2
				2	Connection	0*	1	Table 6-2
3	Service Record	1	1	1	Overall	0*	1	Table 6-2
				2	Age	1	1	Figure 6-1
				4	Loading	0*	1	Table 6-3
Overall HI De-Rating Multiplier (DR)				PCB				Table 6-4
*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.								

6.1.2 *Condition Criteria*

Visual Inspections

Table 6-2 Visual Inspection Criteria

Score	**Condition Description**			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Loading History

Table 6-3 Loading History

Data: S1, S2, S3, …, SN recorded data (average daily loading)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 Score = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then Score should be multiplied by 0.6 to show the effect of overheating.

Age

Assume that the failure rate Vault Transformers exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f	= failure rate of an asset (percent of failure per unit time)
t	= time
α, β	= constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f	= survivor function
P_f	= cumulative probability of failure

Assuming that at the ages of 40 and 55 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

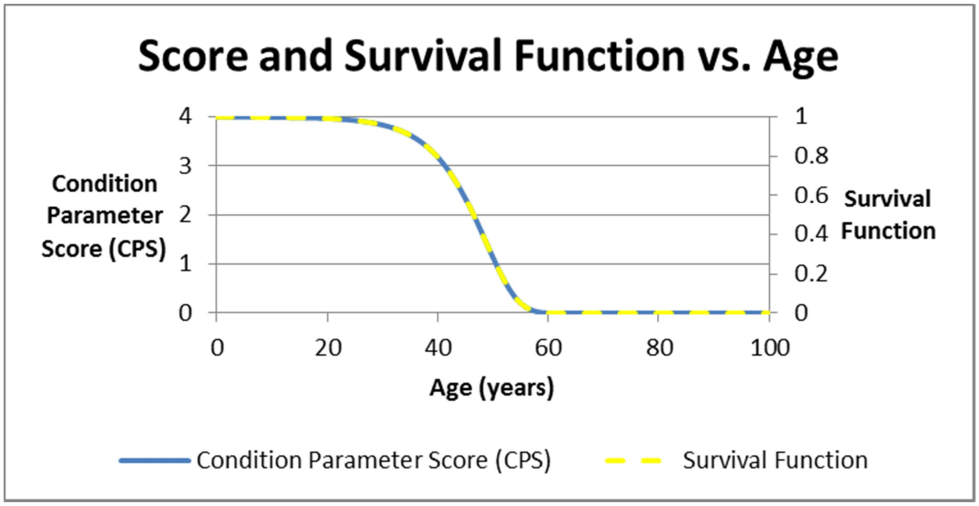

Figure 6-1 Vault Transformers Age Criteria

De-Rating (DR)

A de-rating multiplier will be applied to units that have a certain level of PCB.

Table 6-4 De-Rating Criteria

Condition		De-Rating Multiplier (DR)
If	PCB > 2 ppm	0.25
Else		1

6.2 Age Distribution

The average age of all single phase units was 33 years.

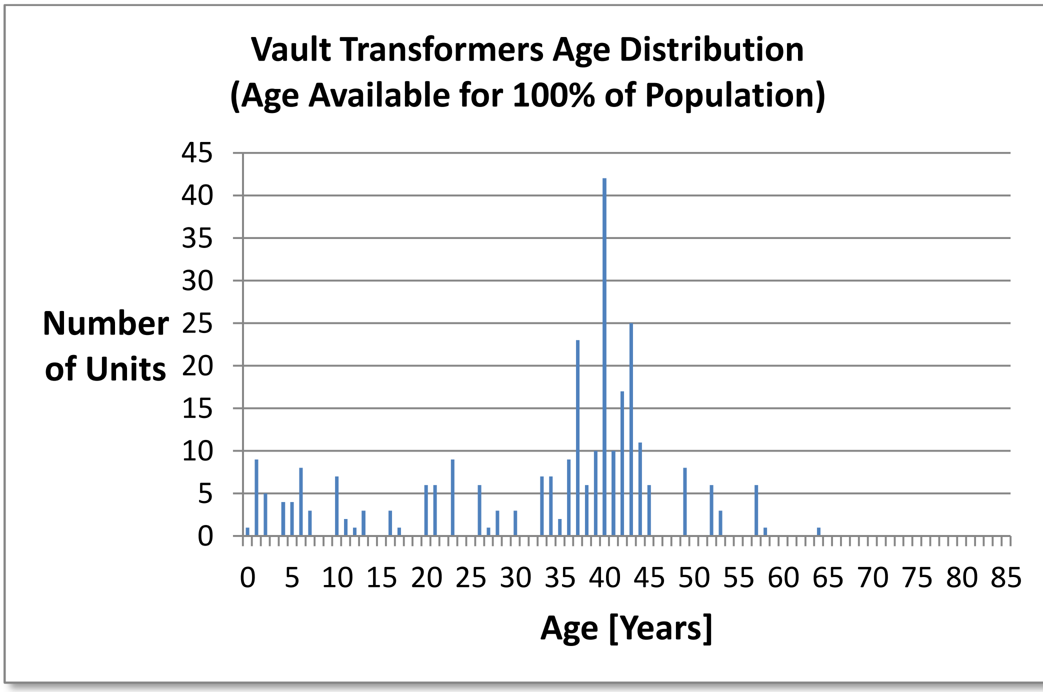

Figure 6-2 Vault Transformers Age Distribution

6.3 Health Index Results

There are 285 Vault Transformerss at TBH. Of these, all had sufficient data for Health Indexing.

The average Health Index for this asset group was 87%. Approximately 9% of the population was in “poor” or “very poor” condition. These include units that have PCBs.

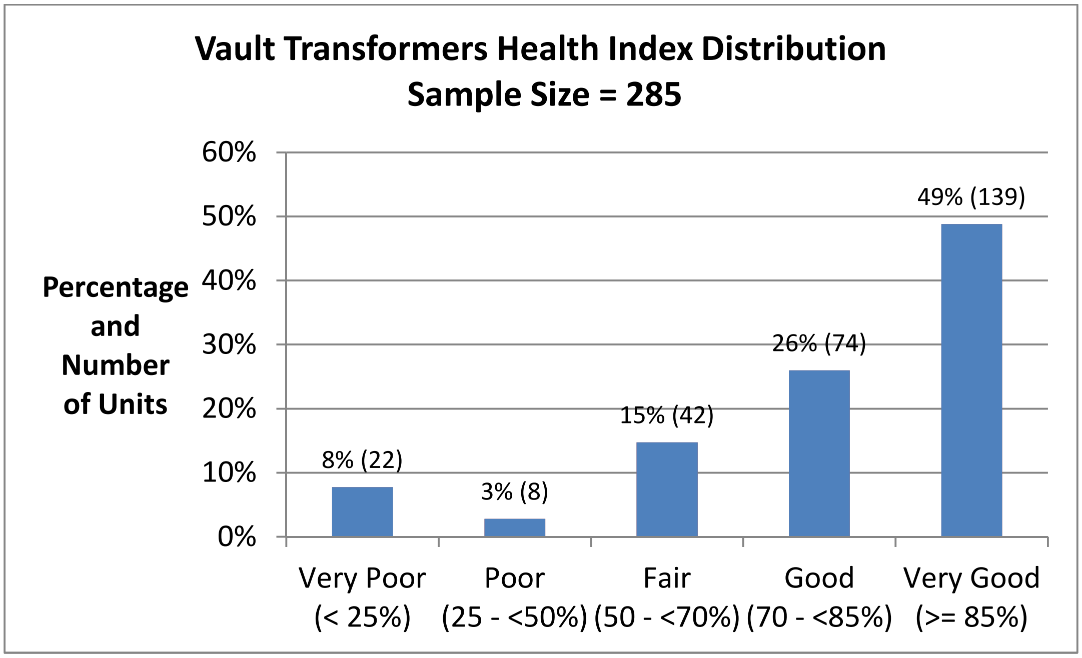

Figure 6-3 Vault Transformers Health Index Distribution

6.4 Flagged for Action Plan

As it is assumed that Vault Transformers were reactively replaced, the flagged for action plan was based on the asset failure rate. The Flagged for Action Plan was as follows:

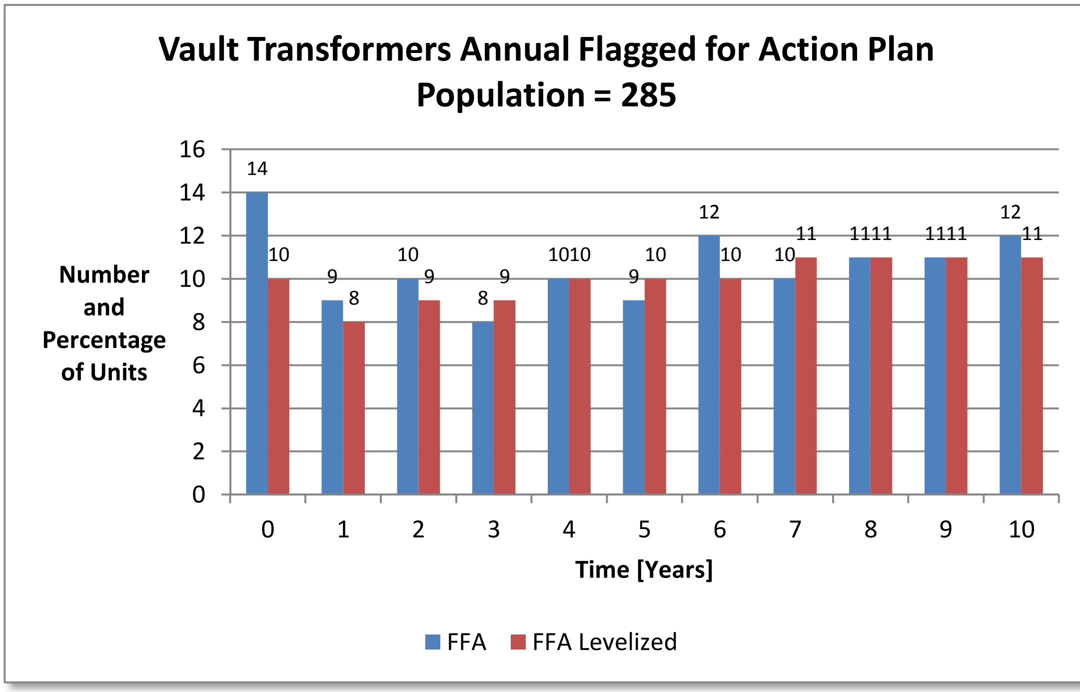

Figure 6-4 Vault Transformers Flagged for Action Plan

6.5 Data Analysis

The data available for Vault Transformers are age and PCB content. The average DAI was 100%. The data gaps, which are primarily from inspections, are as follows:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Enclosure	Physical Condition	☆☆	Transformer oil tank	Tank surface rust or deterioration due to environmental factors	Visual inspection/ Corrective Maintenance
Access		☆	Transformer	Access to transformer	Visual inspection/ Corrective Maintenance
Oil Leak	Connection & Insulation	☆☆☆	Transformer tank	Leakage	Visual inspection/ Corrective Maintenance
Connection		☆☆	Transformer connection	Poor connection	Visual inspection/ Corrective Maintenance
Overall	Service Record	☆	Transformer	General status evaluation based on routine operation and inspection	Visual inspection/ Corrective Maintenance
Loading		☆☆	Transformer load	Monthly 15 min peak load throughout years	Operation record

7 Overhead Switches

7.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the "worst" and "best" scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is "4".

7.1.1 *Condition and Sub-Condition Parameters*

Table 7-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	**Description**	**Weight (WCP)**	**De-Rating Multiplier (DR_CP)**	**m**	**Description**	**Weight (WSCP)**	**De-Rating Multiplier (DR_SCP)**	**SCP Criteria**
1	Operating Mechanism	0*	**1**	1	Motor/ Manual/ Switch Mounting	0*	**1**	Table 7-3
2	Arc Extinction / Switch	0*	**1**	1	Arc Suppressor / Switch Blade	0*	**1**	Table 7-2
3	Insulation	0*	**1**	1	Insulator	0*	**1**	Table 7-2
4	Service Record	**1**	**1**	1	Age	**1**	**1**	Figure 7-1 **Error! Reference source not found.**
				2	Operations Record	0*	0*	Table 7-2
*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.								

7.1.2 *Condition Criteria*

<u>**Operations Record**</u>

Table 7-2 Operations Records Criteria

Score	Condition Description
4	Operated in Last Year
3.5	Operated in Last 3 Years
3	Operated in Last 5 Years
0	Not Operated in Last Year

Visual Inspections

Table 7-3 Visual Inspection Criteria

Score	Condition Description			
4	No Apparent Issues	Good	Pass	OK
3	Mild Severity			
2	Medium Severity	Fair		
1	Severe			
0	Very Severe	Poor	Fail	Not OK

Age

Assume that the failure rate Overhead Switches exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f - e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

Assuming that at the ages of 45 and 60 years the probability of failures (P_f) for 27.6 kV, 44 kV, and Inline Switches are 20% and 99% respectively results in the survival curve shown below. It follows that the Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figure below.

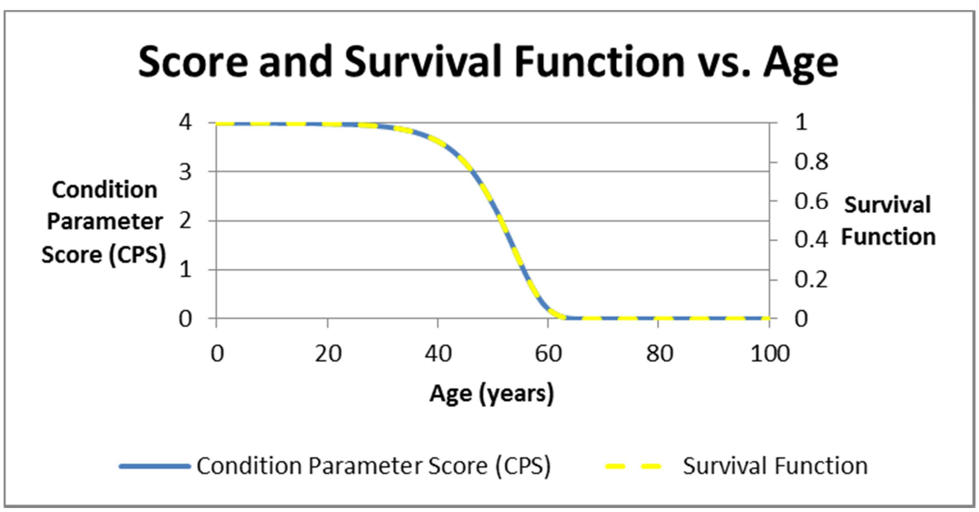

Figure 7-1 Overhead Switches Age Criteria

7.2 Age Distribution

The average age of all units was 32 years. Age distributions for all sub-categories are shown.

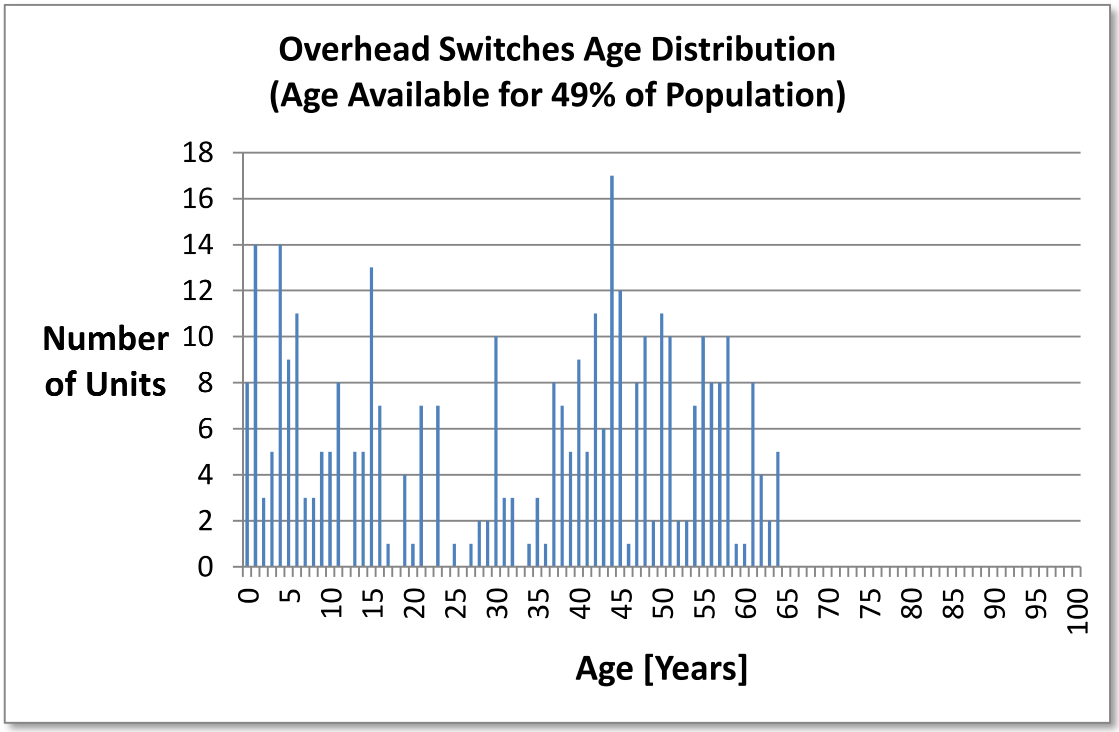

Figure 7-2 ALL Overhead Switches Age Distribution

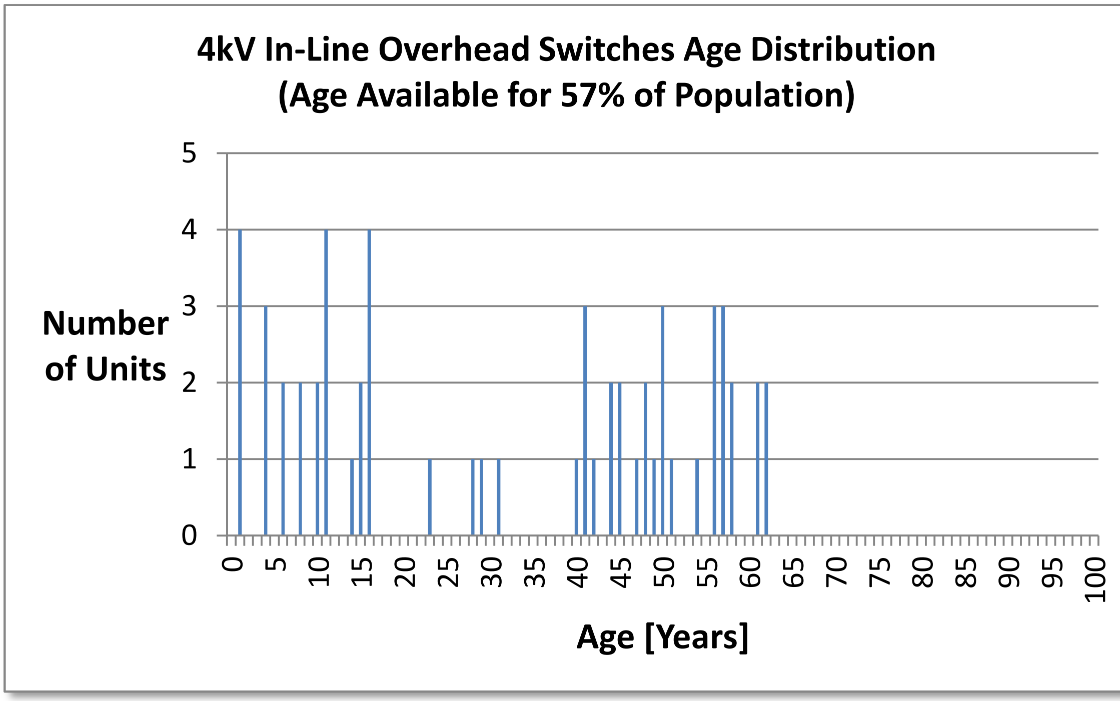

Figure 7-3 4kV In-Line Overhead Switches Age Distribution

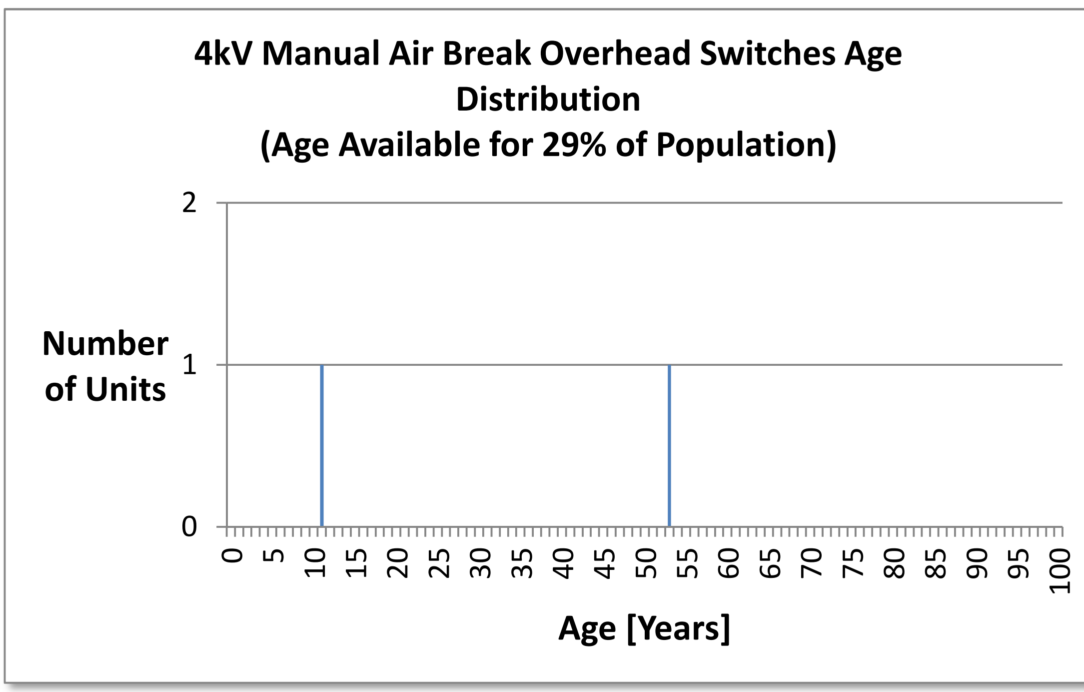

Figure 7-4 4kV Manual Air Break Overhead Switches Age Distribution

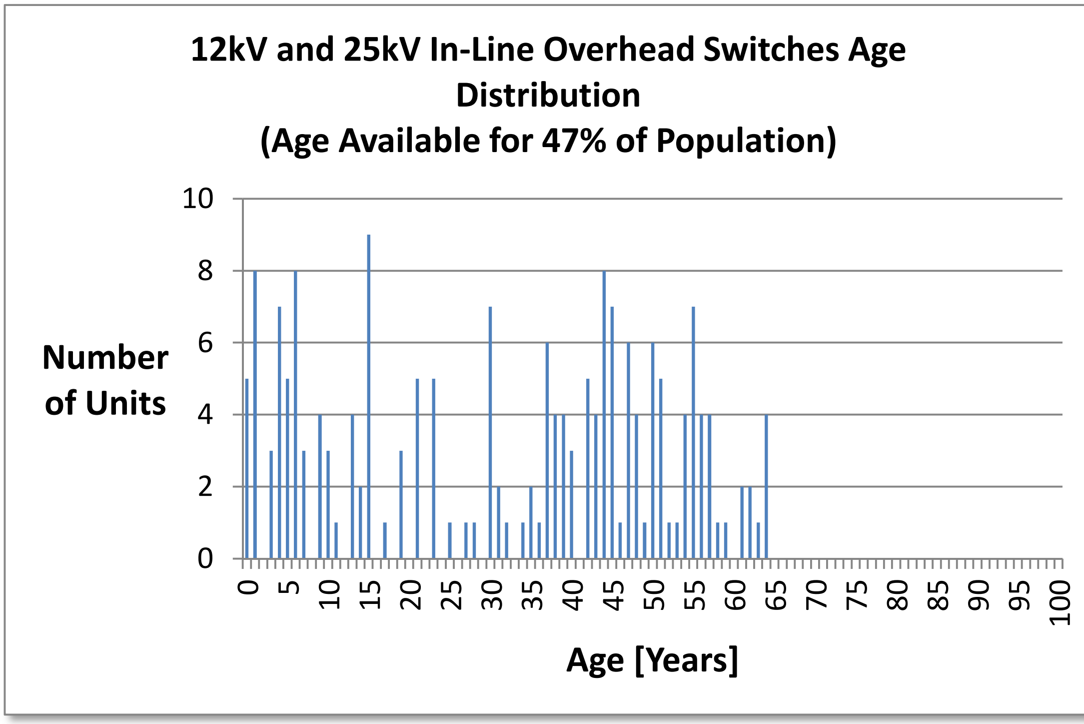

Figure 7-5 12 and 25kV In-Line Overhead Switches Age Distribution

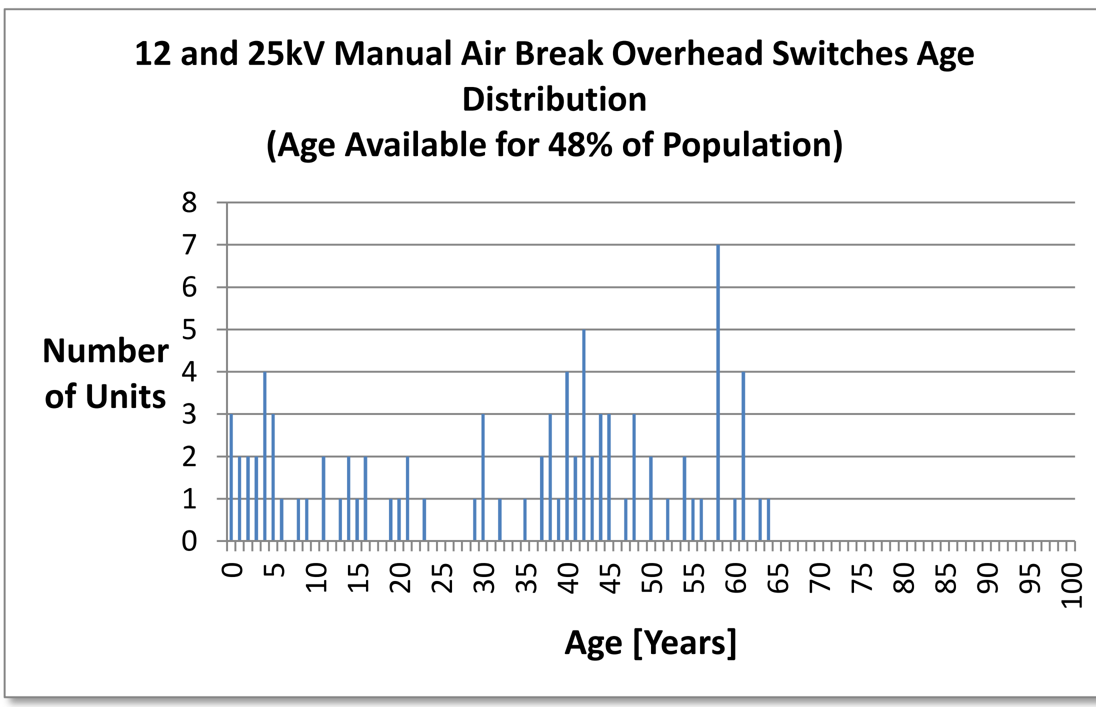

Figure 7-6 12 and 25kV Manual Air Break Overhead Switches Age Distribution

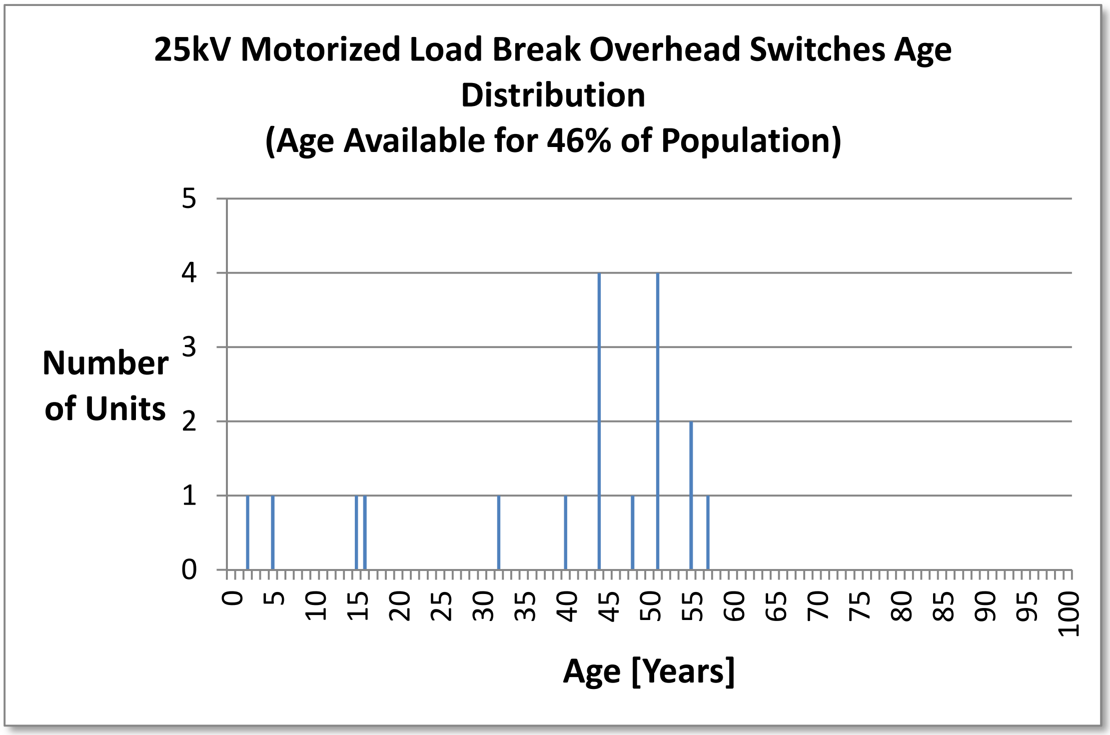

Figure 7-7 12 and 25kV Motorized Load Break Overhead Switches Age Distribution

7.3 Health Index Results

There are 729 Overhead Switches at TBH. Of these, only 305 units had sufficient data for Health Indexing. The average Health Index for this asset group was 76%. Approximately 19% were in "poor" or "very poor" condition. Broken down into sub-categories, the results are summarized as follows:

Sub-Category	Population	Sample Size	Average HI	% in Poor/Very Poor
ALL	*729*	*305*	*76%*	*19%*
4kV In-Line	101	46	71%	26%
4kV Manual Air Break	7	2	70%	50%
12 and 25kV In-Line	399	148	80%	18%
12 and 25kV Manual Air Break	183	74	78%	18%
25kV Motorized Load Break	39	10	67%	30%

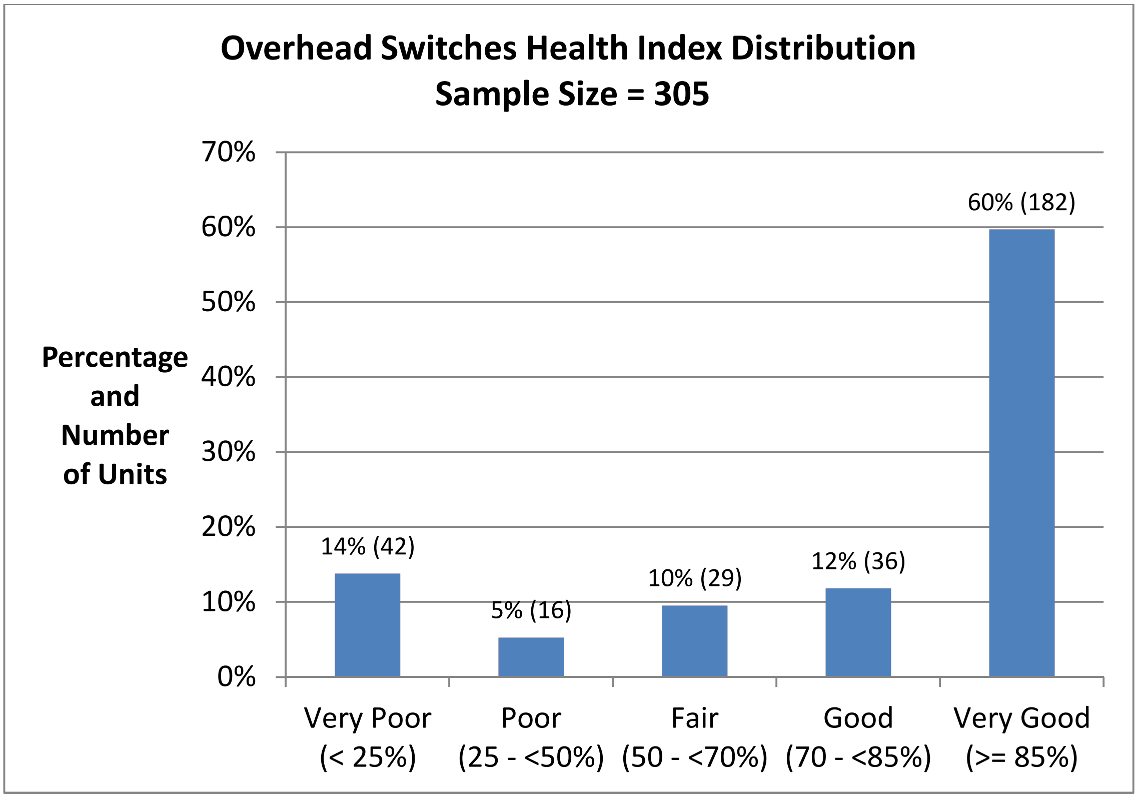

Figure 7-8 ALL Overhead Switches Health Index Distribution

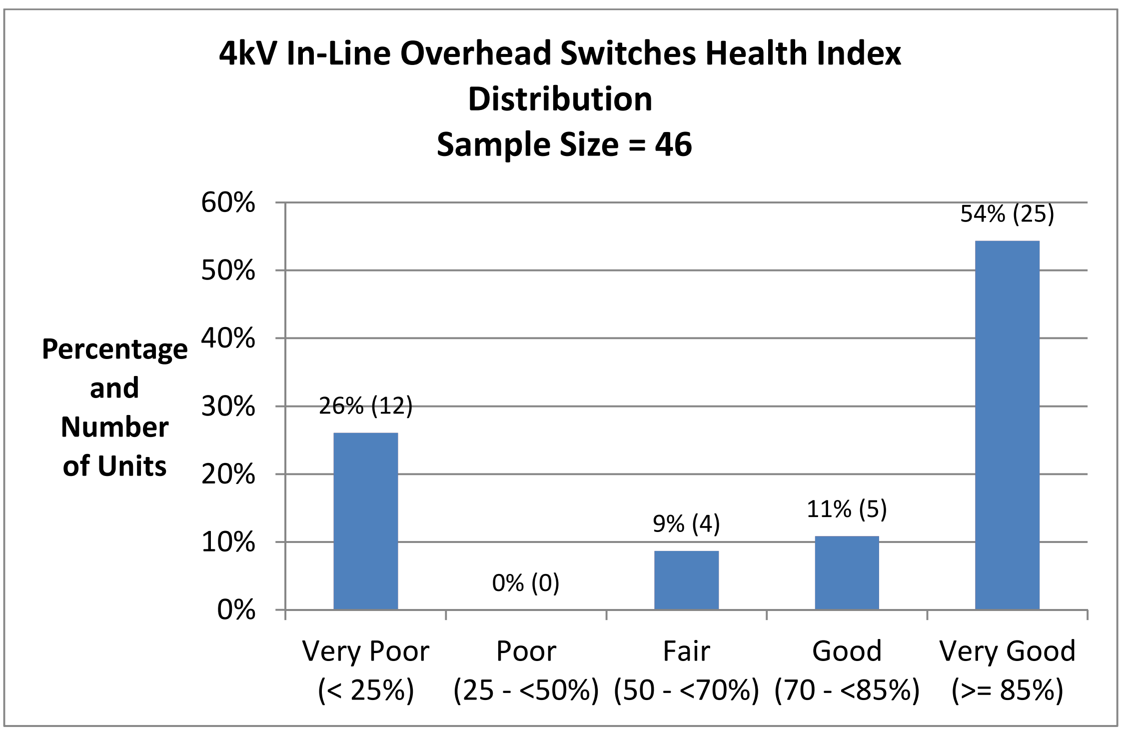

Figure 7-9 4kV In-Line Overhead Switches Health Index Distribution

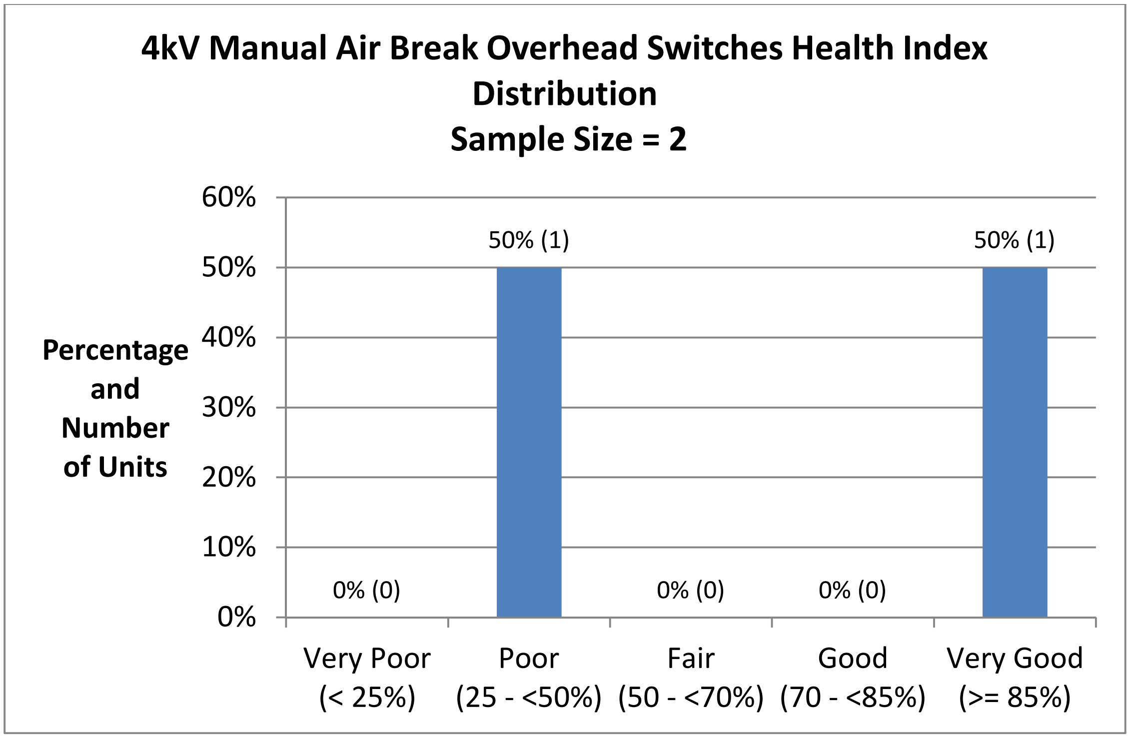

Figure 7-10 4kV Manual Air Break Overhead Switches Health Index Distribution

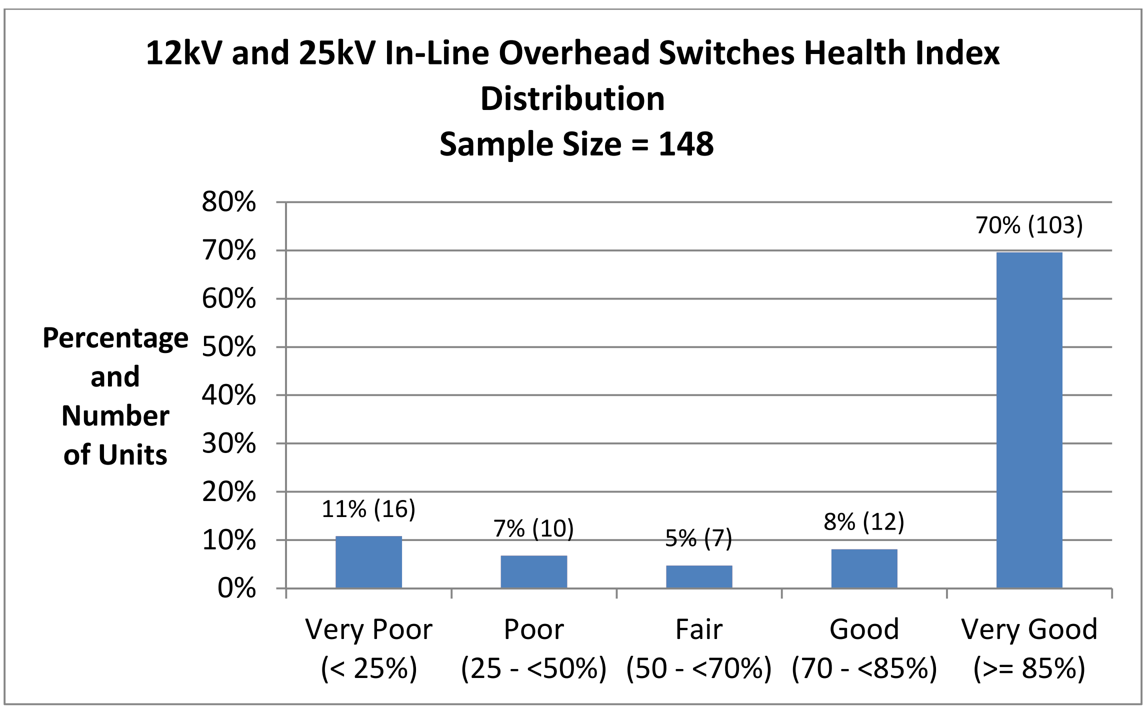

Figure 7-11 12 and 25kV In-Line Overhead Switches Health Index Distribution

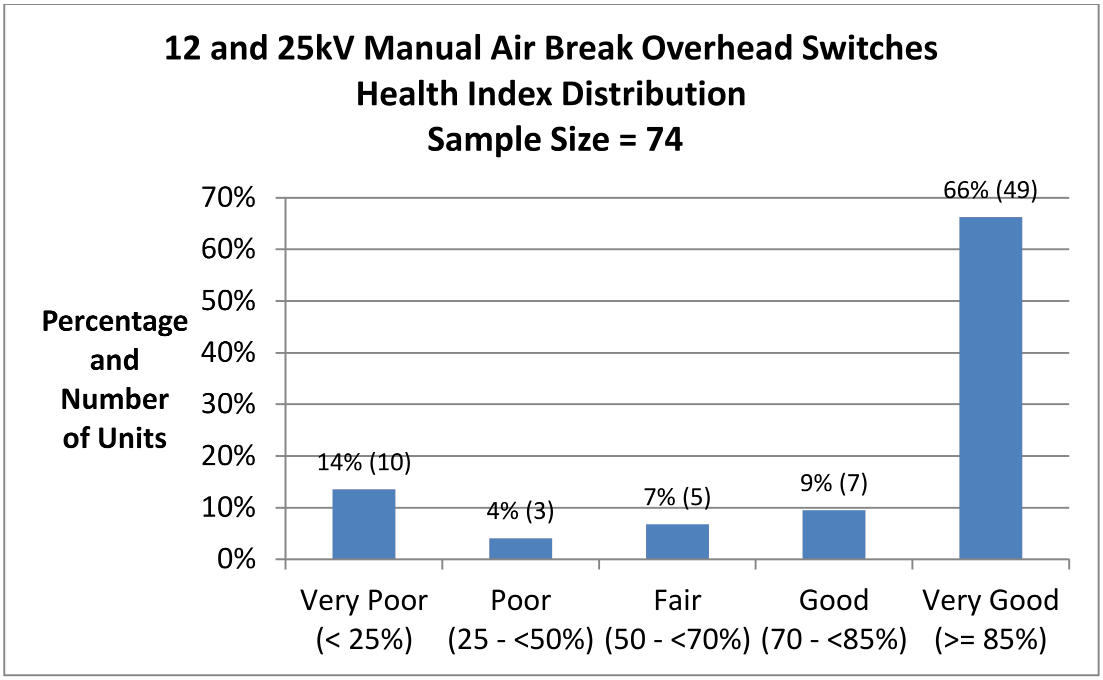

Figure 7-12 12 and 25kV Manual Air Break Overhead Switches Health Index Distribution

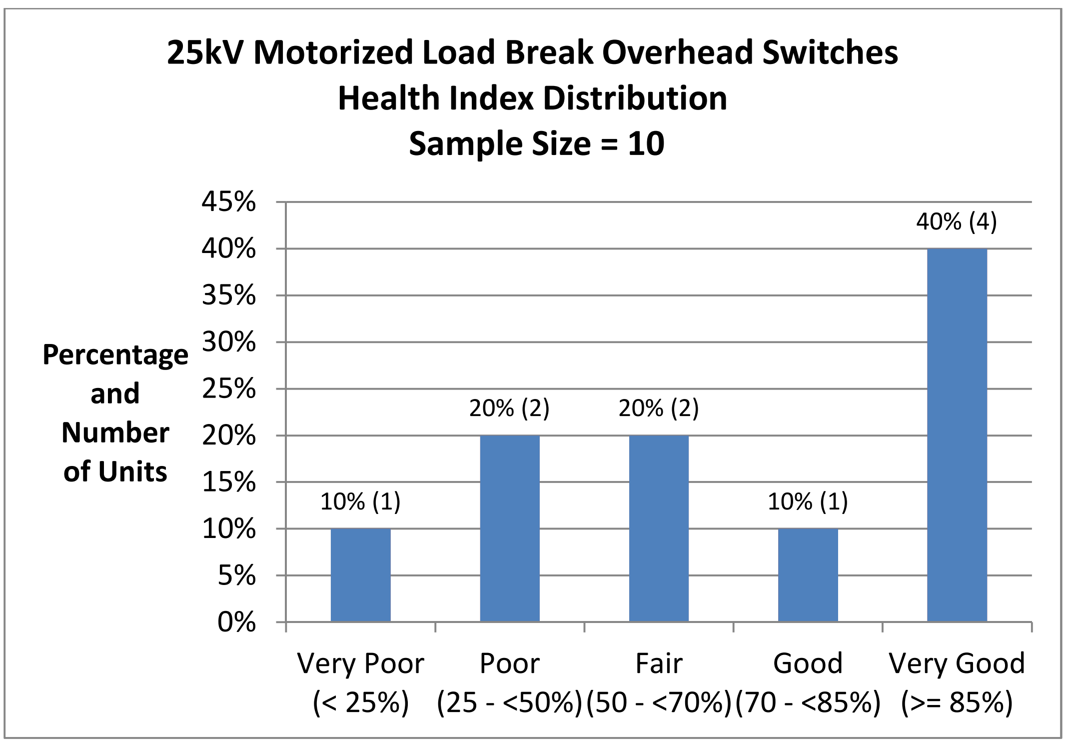

Figure 7-13 12 and 25kV Motorized Load Break Overhead Switches Health Index Distribution

7.4 Flagged for Action Plan

As it is assumed that Overhead Switches were reactively replaced, the flagged for action plan was based on the asset failure rate.

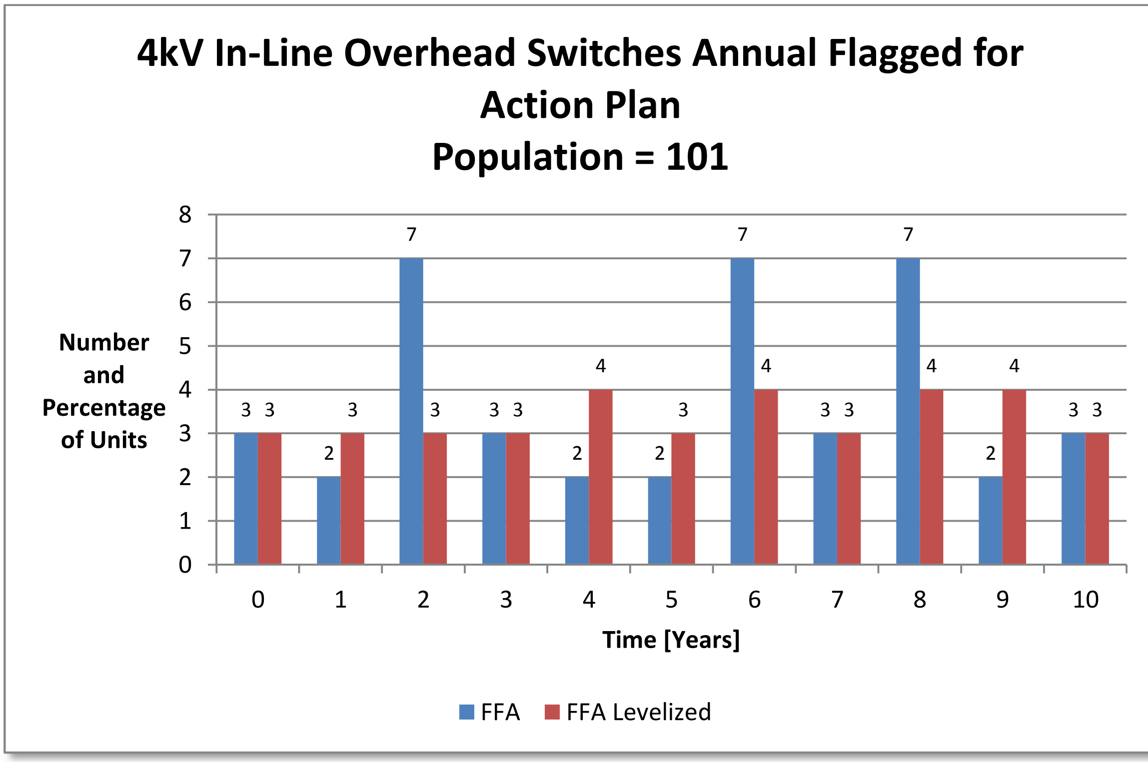

Figure 7-14 4kV In-Line Overhead Switches Flagged for Action Plan

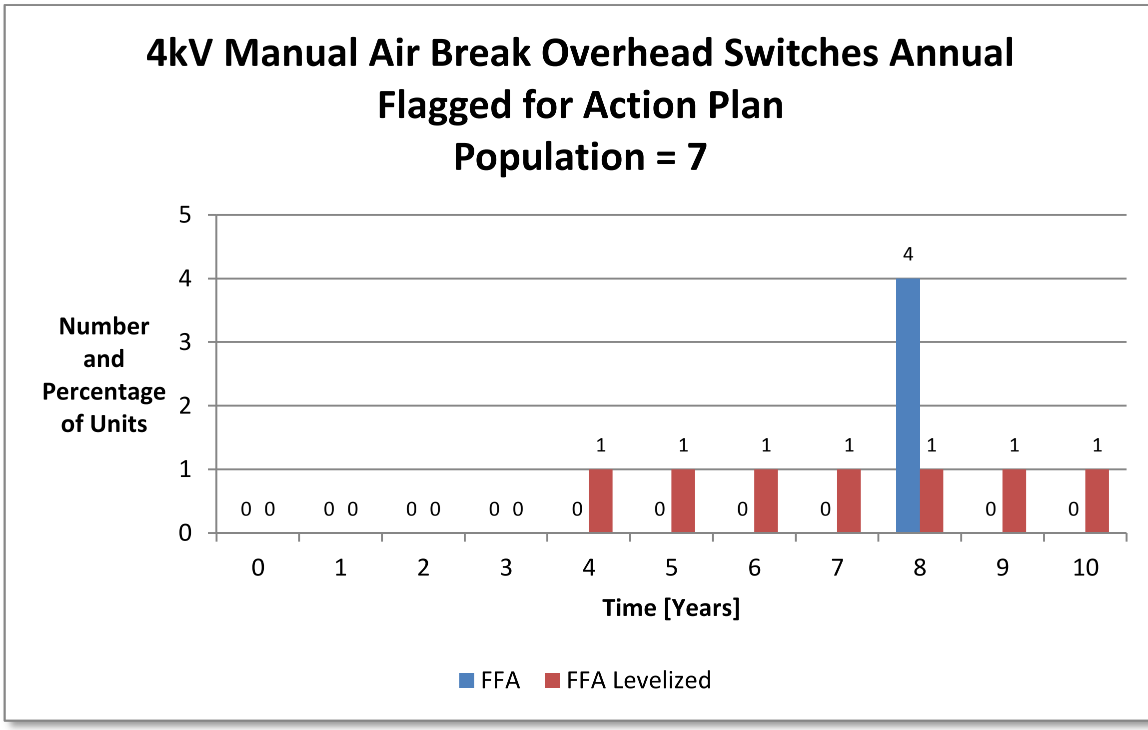

Figure 7-15 4kV Manual Air Break Overhead Switches Flagged for Action Plan

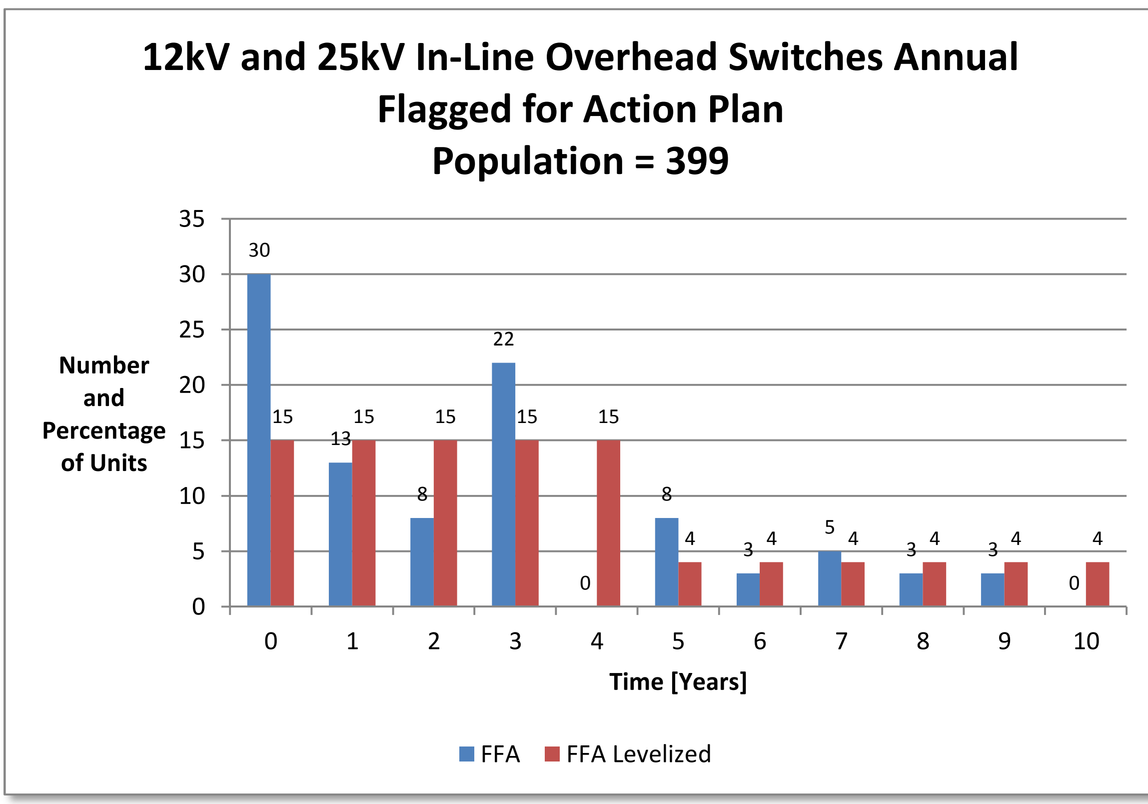

Figure 7-16 12 and 25kV In-Line Overhead Switches Flagged for Action Plan

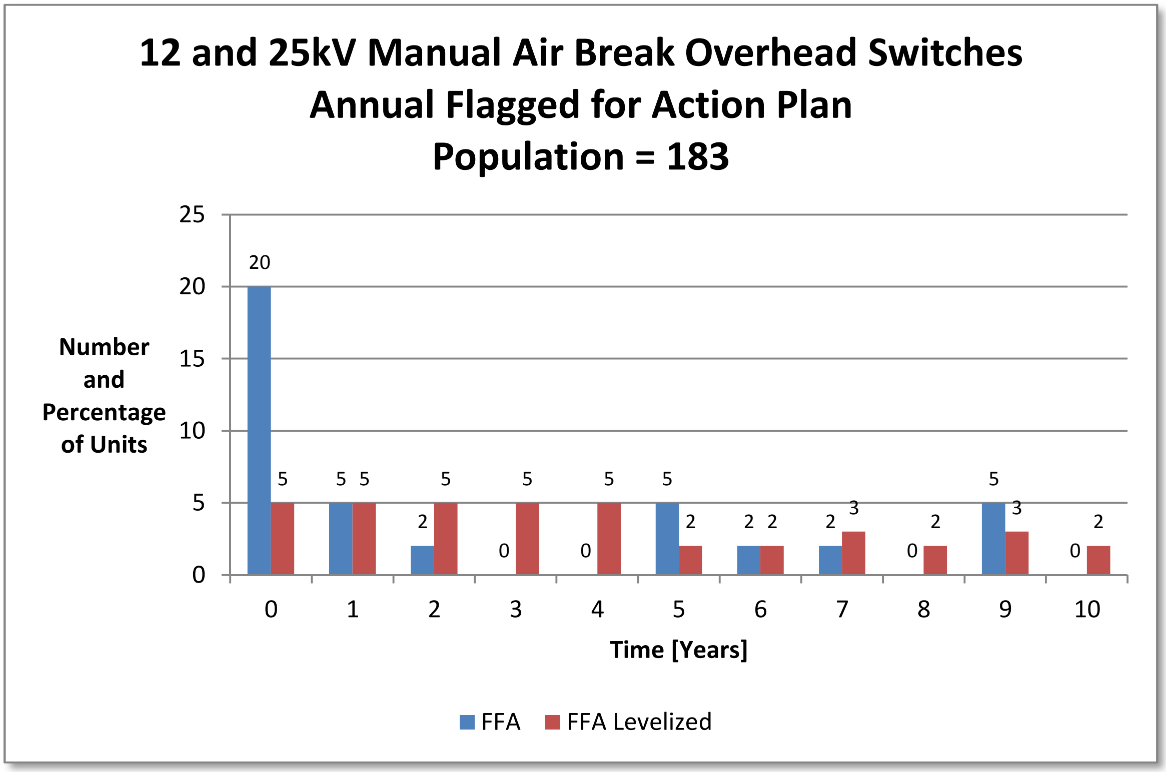

Figure 7-17 12 and 25kV Manual Air Break Overhead Switches Flagged for Action Plan

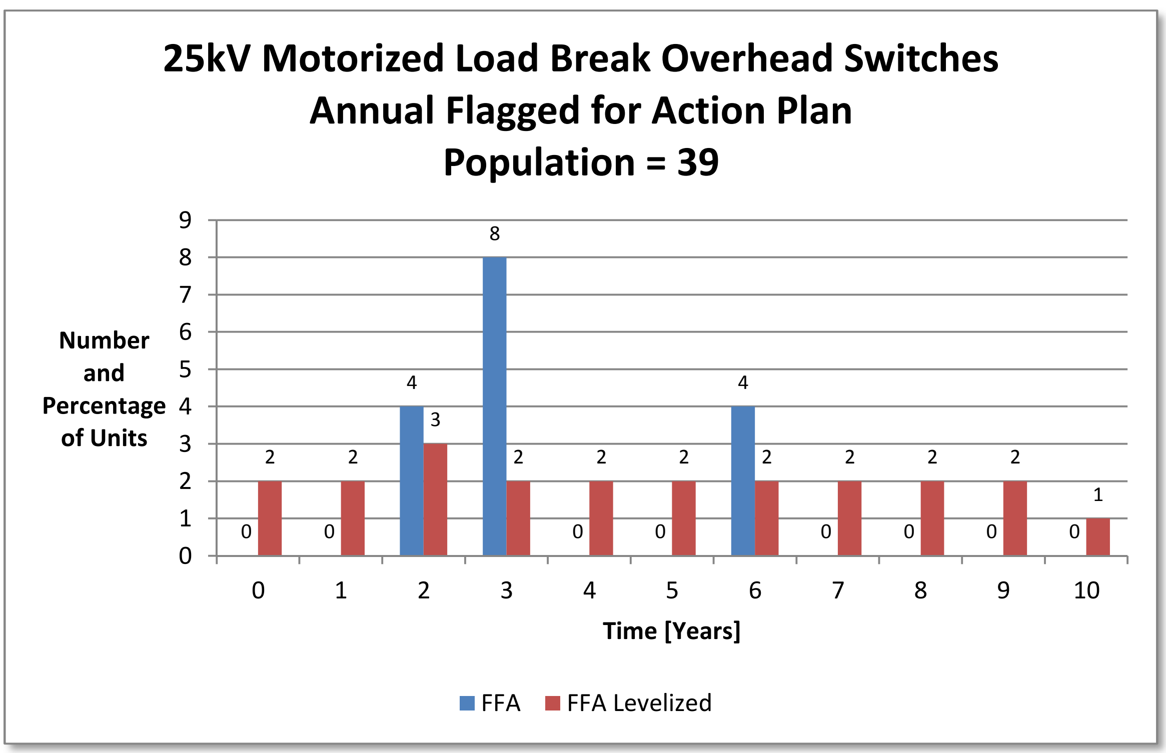

Figure 7-18 12 and 25kV Motorized Load Break Overhead Switches Flagged for Action Plan

7.5 Data Analysis

Age was the only information available for overhead and underground switches. Further, as can be seen from the low DAIs of these asset categories, fewer than half of the switches had age information. Age should be collected for the remainder of the population.

Sub-Category	DAI
ALL	42%
4kV In-Line	46%
4kV Manual Air Break	29%
12 and 25kV In-Line	37%
12 and 25kV Manual Air Break	40%
25kV Motorized Load Break	26%

Operations records and inspection/corrective maintenance records should be collected (e.g. condition related to switch, operating mechanism, insulation, arc extinguishing mechanism). Such information would provide insight to actual condition.

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Motor/Manual Operation	Operation Mechanism	☆☆☆	Switch Operating system	Mechanical part and linkage issue	On-site manual inspection/ Corrective Maintenance Records
Mechanical Support		☆	Switch support	Loose installation	
Arc Horn	Arc Extinction	☆	Switch operation	Arc horn surface worn-out	
Arc Interrupter		☆☆	Switch arc extinction	Arc extinction part surface worn-out	
Insulator	**Insulation**	☆	Support insulator	Crack	
Switch Condition	**Service Record**	☆☆☆	Blade	Blade condition	

8 25kV Underground Load Break Switches

8.1 Health Index Formula

See Section 7.1.

8.2 Age Distribution

The average age of this asset group is 31 years.

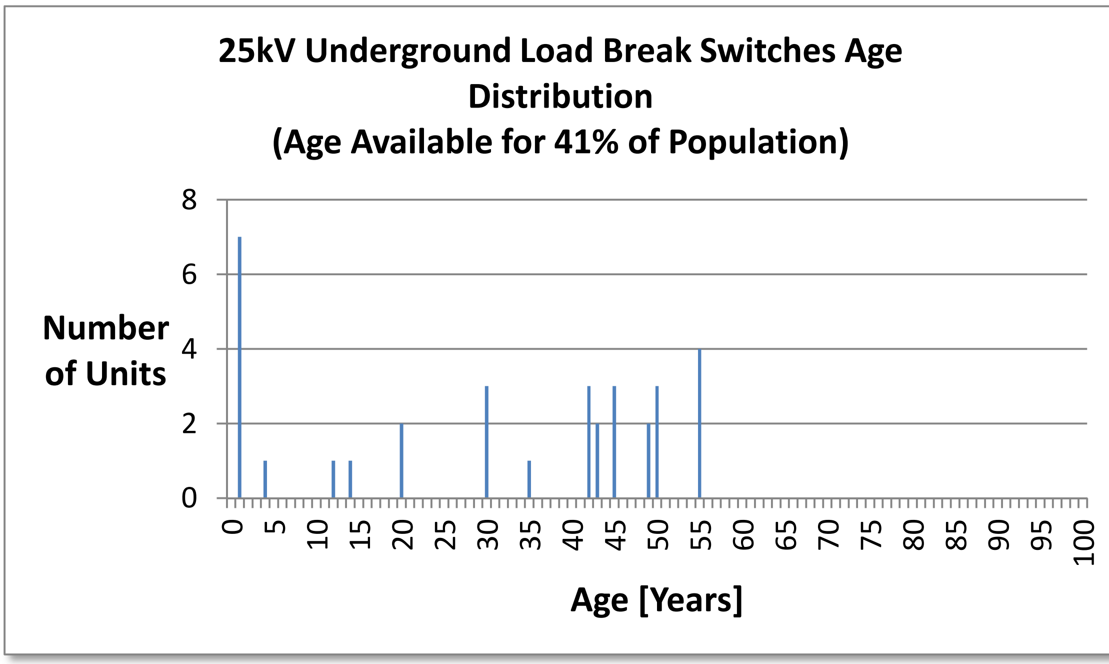

Figure 8-1 ALL 25kV Underground Load Break Switches Age Distribution

8.3 Health Index Results

There are 80 Overhead Switches at TBH. Of these, only 30 units had sufficient data for Health Indexing. The average Health Index for this asset group was 81%. Approximately 13% were in “poor” condition.

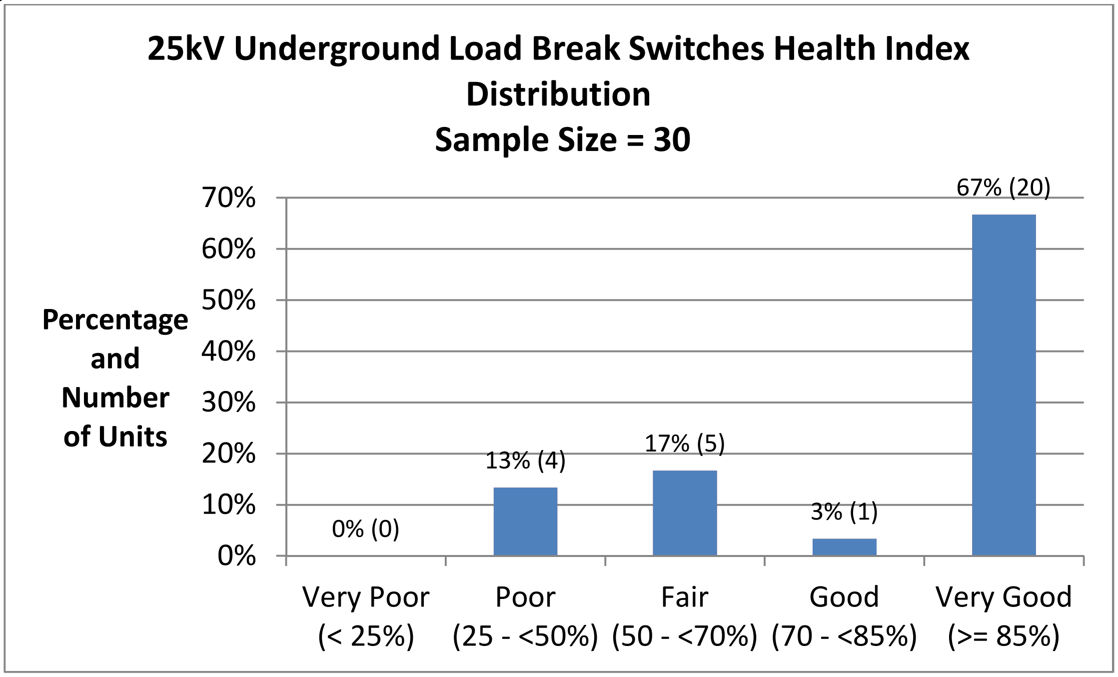

Figure 8-2 ALL 25kV Underground Load Break Switches Health Index Distribution

8.4 Flagged for Action Plan

As it is assumed that 25kV Underground Load Break Switches were reactively replaced, the flagged for action plan was based on the asset failure rate.

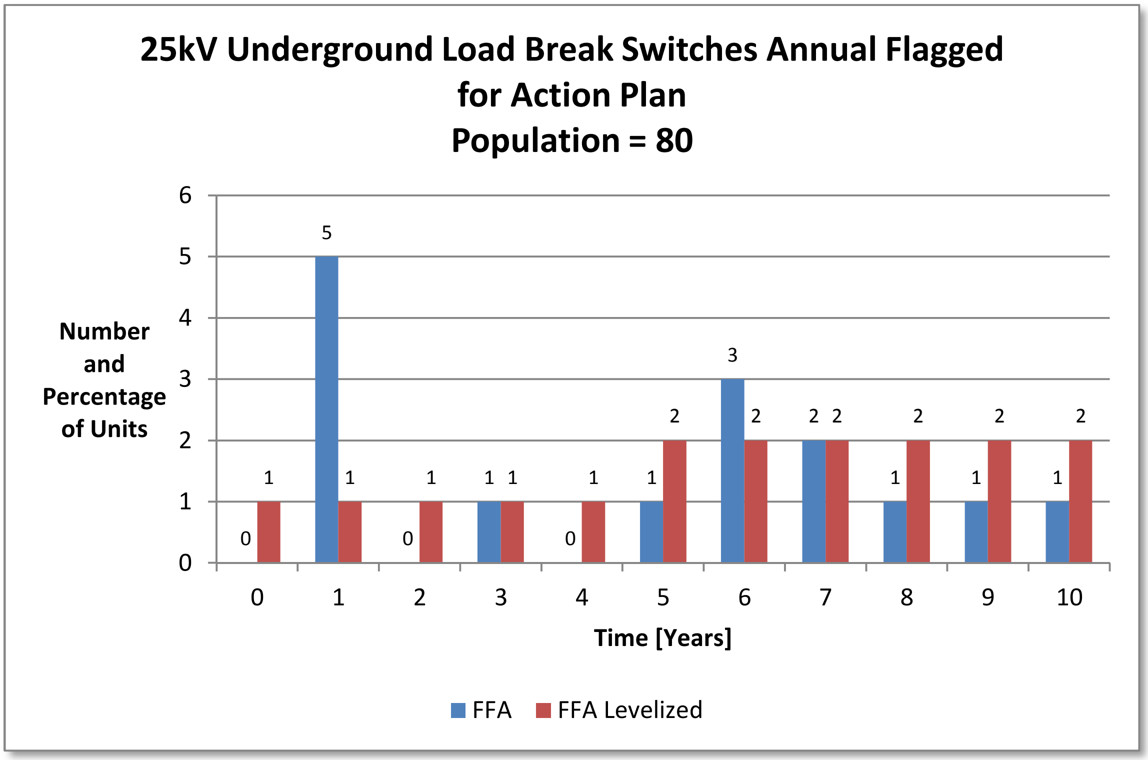

Figure 8-3 25kV 25kV Underground Load Break Switches Flagged for Action Plan

8.5 Data Analysis

Only age was available for this asset. At 38%, the DAI was low. Age information should therefore be collected for the remainder of the population. See Section 8.5 for data gaps.

9 Underground Cables

9.1 Health Index Formula

Assume a parameter scoring system of 0 through 4, where 0 and 4 represent the “worst” and “best” scores respectively. Thus, the maximum score for any condition or sub-condition parameter (maximum CPS and CPF) is “4”.

9.1.1 *Condition and Sub-Condition Parameters*

Table 9-1 Condition Parameter and Weights

Condition Parameter (CP)				Sub-Condition Parameter (SCP)				
n	Description	Weight (WCP)	De-Rating Multiplier (DR_CP)	m	Description	Weight (WSCP)	De-Rating Multiplier (DR_SCP)	SCP Criteria
1	Cable Tests	**0***	**1**	1	Cable Test Results	**0***	**1**	Test Dependent
2	Service Record	**1**	**1**	1	Age	**1**	**1**	Figure 9-1 Figure 9-2
Overall HI De-Rating Multiplier (DR)				Number of Failures in last 5 Years*				-
*Data for this parameter was not available; weight was therefore set to 0 and the parameter is effectively excluded from the formula.								

9.1.2 *Condition Criteria*

<u>Age</u>

Assume that the failure rate Underground Cables exponentially increases with age and that the failure rate equation is as follows:

$$f = e^{\beta(t-\alpha)}$$

f = failure rate of an asset (percent of failure per unit time)
t = time
α, β = constant parameters that control the rise of the curve

The corresponding survivor function is therefore:

$$S_f = 1 - P_f = e^{-(f-e^{-\alpha\beta})/\beta}$$

S_f = survivor function
P_f = cumulative probability of failure

All the underground cables in this study are of XLPE type. There are three sub categories of such cables based on different installation timelines:

1. non-tree retardant (Non-TR)
2. tree retardant (TR)
3. tree retardant (TR), in-duct

For non-TR cables, assuming that at the ages of 35 and 55 years the probability of failures (P_f) for this asset are 20% and 99% respectively results in the survival curve. For TR in-duct cables and direct buried, the ages of 40 and 60 were used.

The following curves show the survival curves for each cable type. Score for Age is the survival curve normalized to the maximum Score of 4 (i.e. 4*Survival Curve). The Score vs. Age is also shown in the figures.

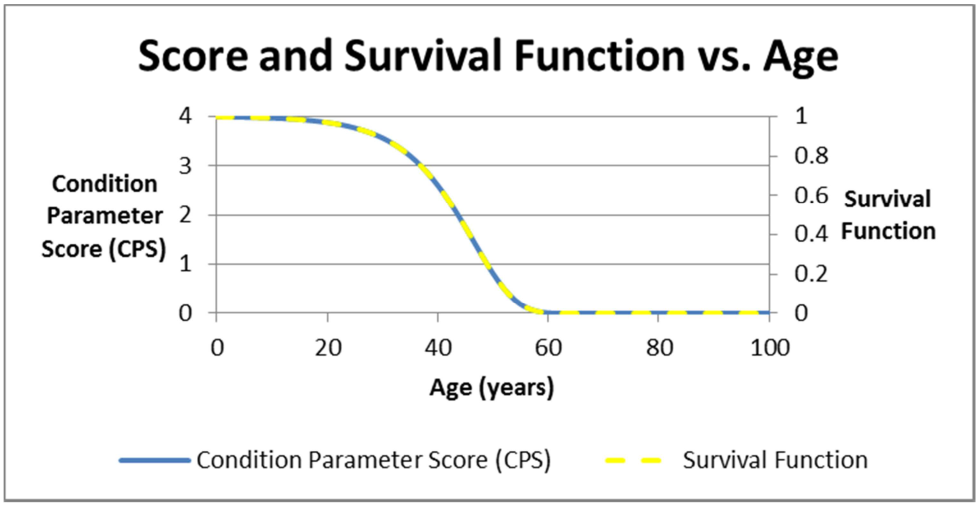

Figure 9-1 Underground Cables Age Criteria – Non-TR

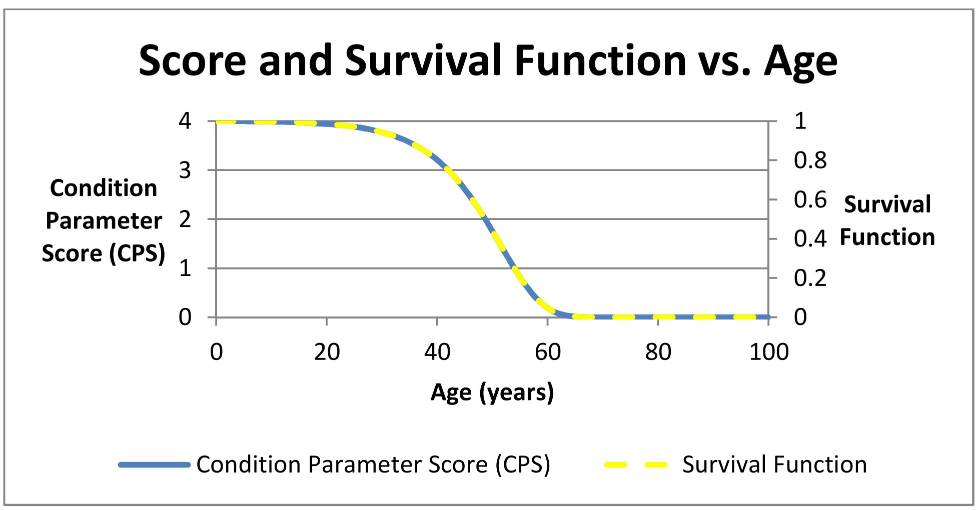

Figure 9-2 Underground Cables Age Criteria – TR (Direct Buried and In Duct)

9.2 Age Distribution

The average age of all cables is 29 years.

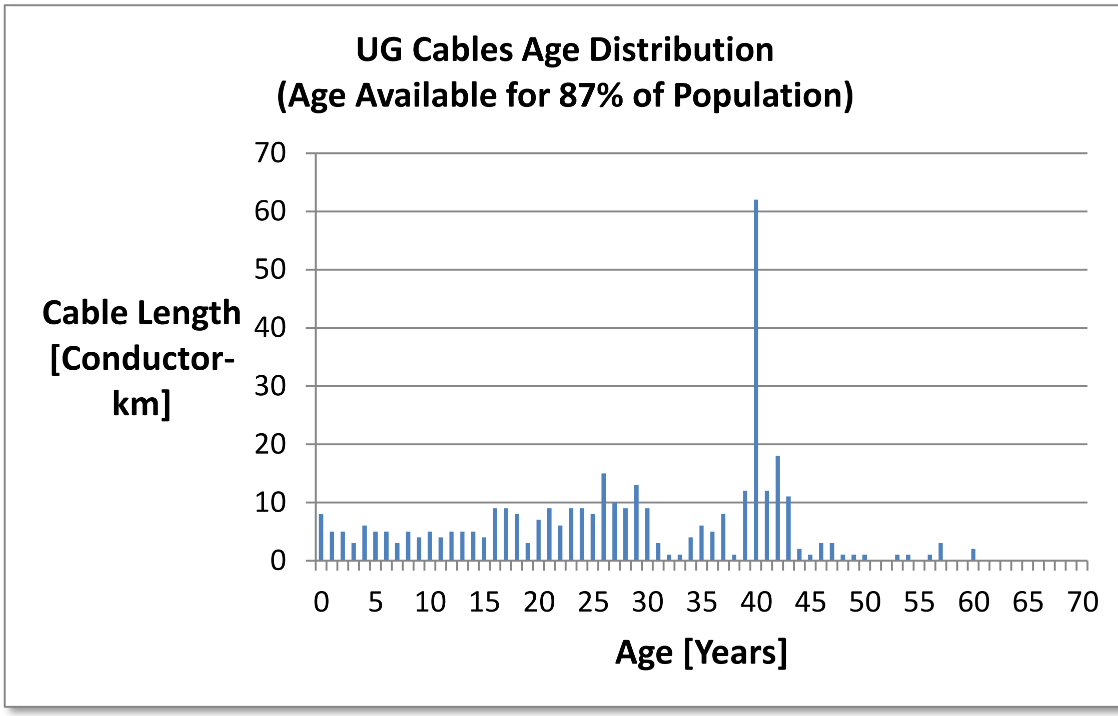

Figure 9-3 ALL Underground Cables Age Distribution

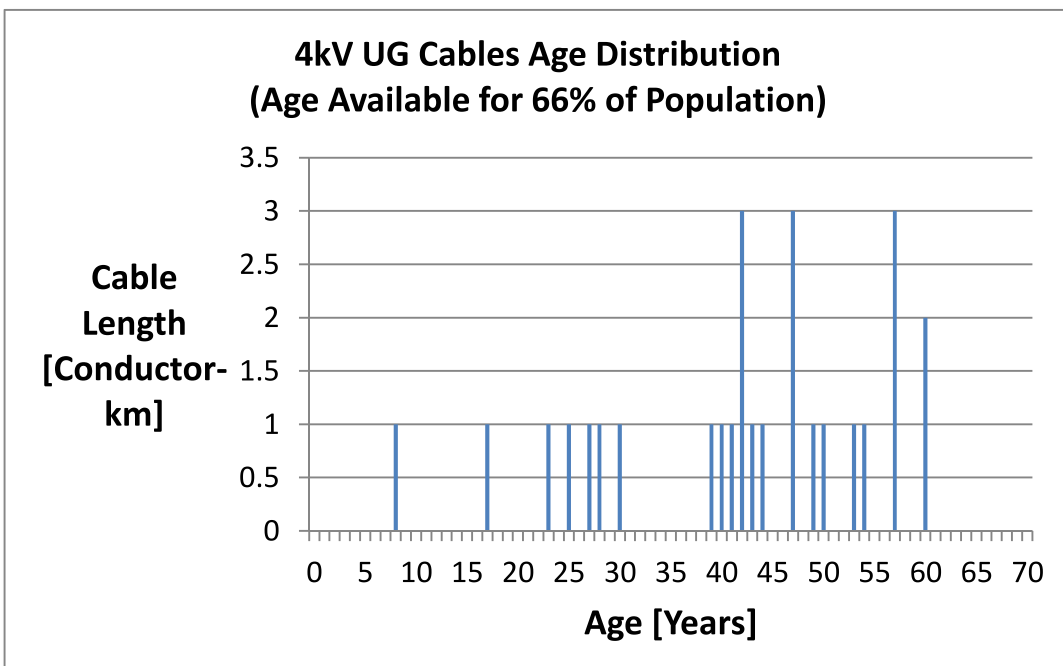

Figure 9-4 4kV Underground Cables Age Distribution

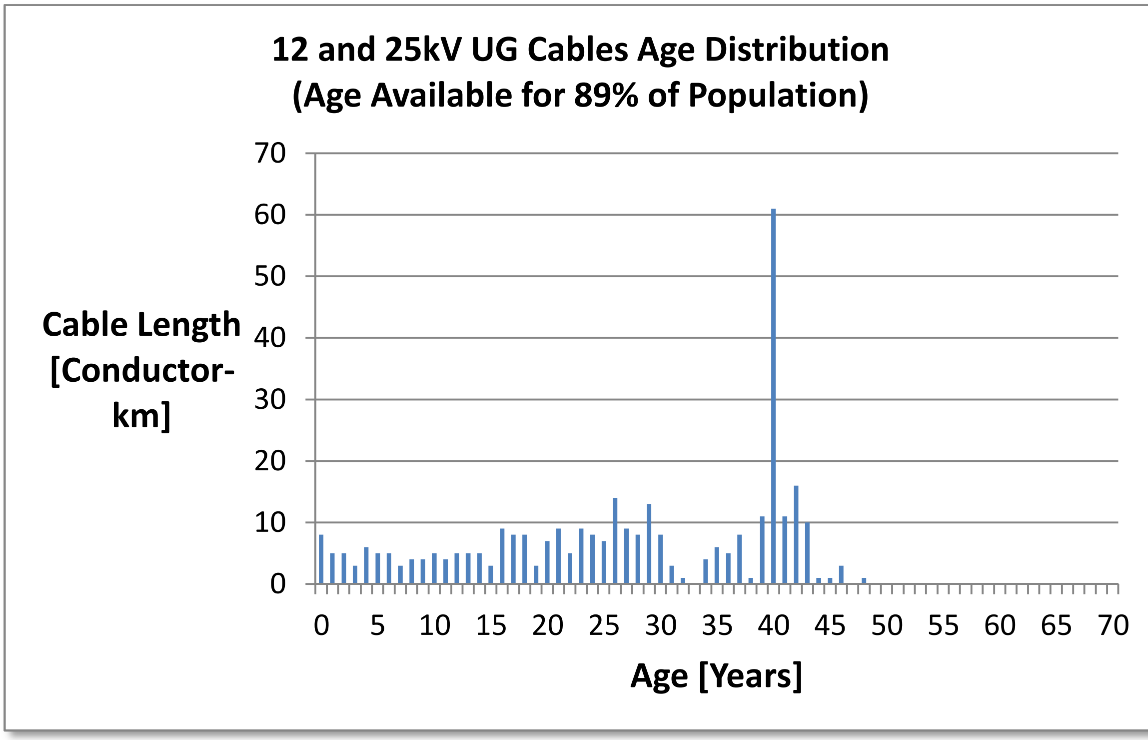

Figure 9-5 12 and 25kV Underground Cables Age Distribution

9.3 Health Index Results

Out of a total of 432 conductor-km of cables, 374 conductor-km of had sufficient data for Health Indexing. The average Health Index for this asset group was 80%. Approximately 6% of population was in "poor" or "very poor" condition.

Sub-Category	Population	Sample Size	Average HI	% in Poor/Very Poor
ALL	432	374	*80%*	*6%*
4kV	44	29	71%	48%
12 and 25kV	387	344	70%	2%

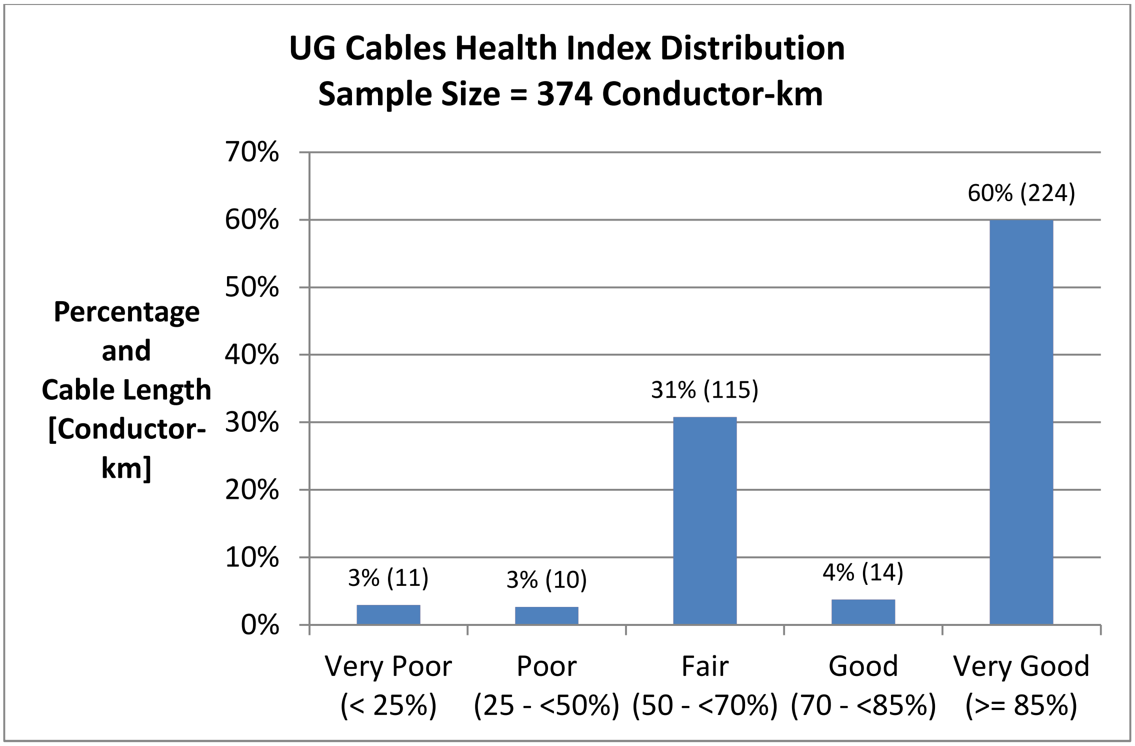

Figure 9-6 ALL Underground Cables Health Index Distribution

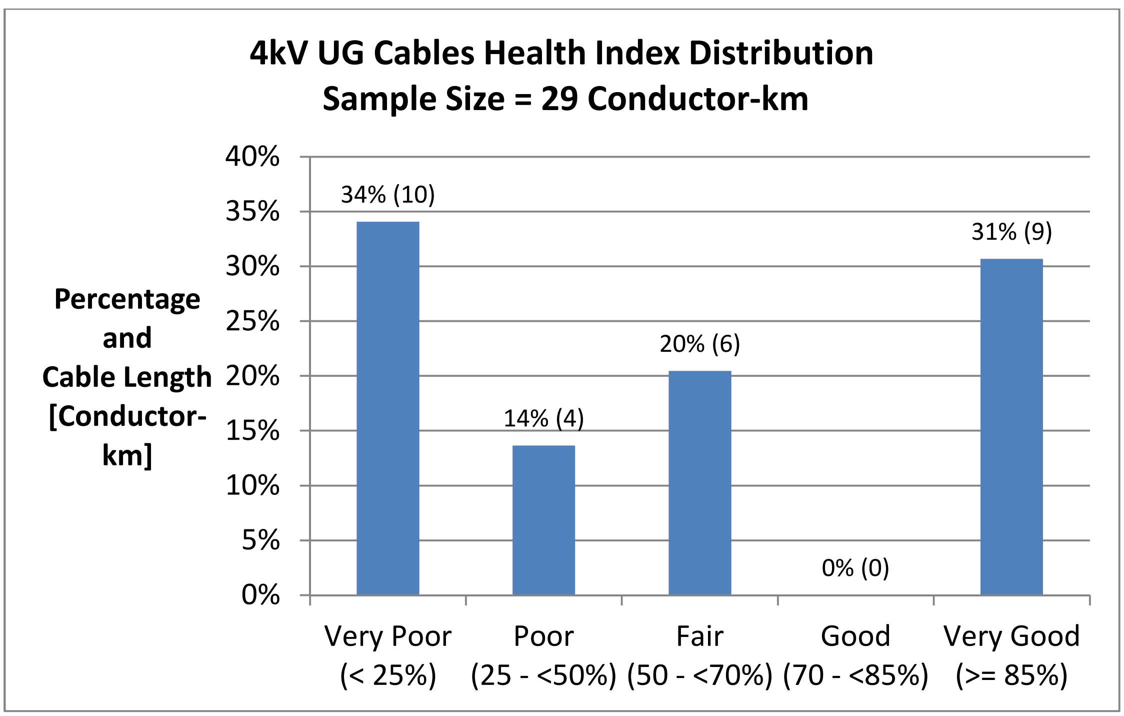

Figure 9-7 4kV Underground Cables Health Index Distribution

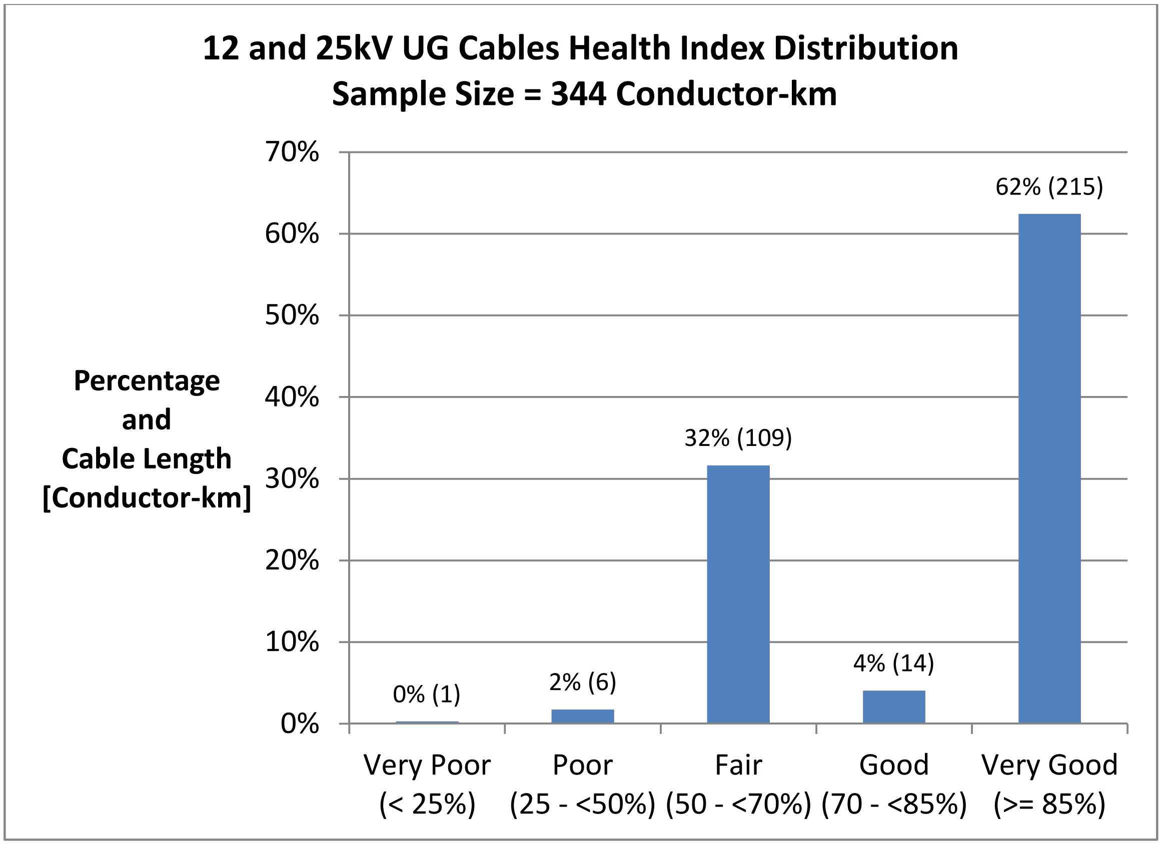

Figure 9-8 12 and 25kV Underground Cables Health Index Distribution

9.4 Flagged for Action Plan

As it is assumed that Underground Cables were reactively replaced, the flagged for action plan was based on the asset failure rate.

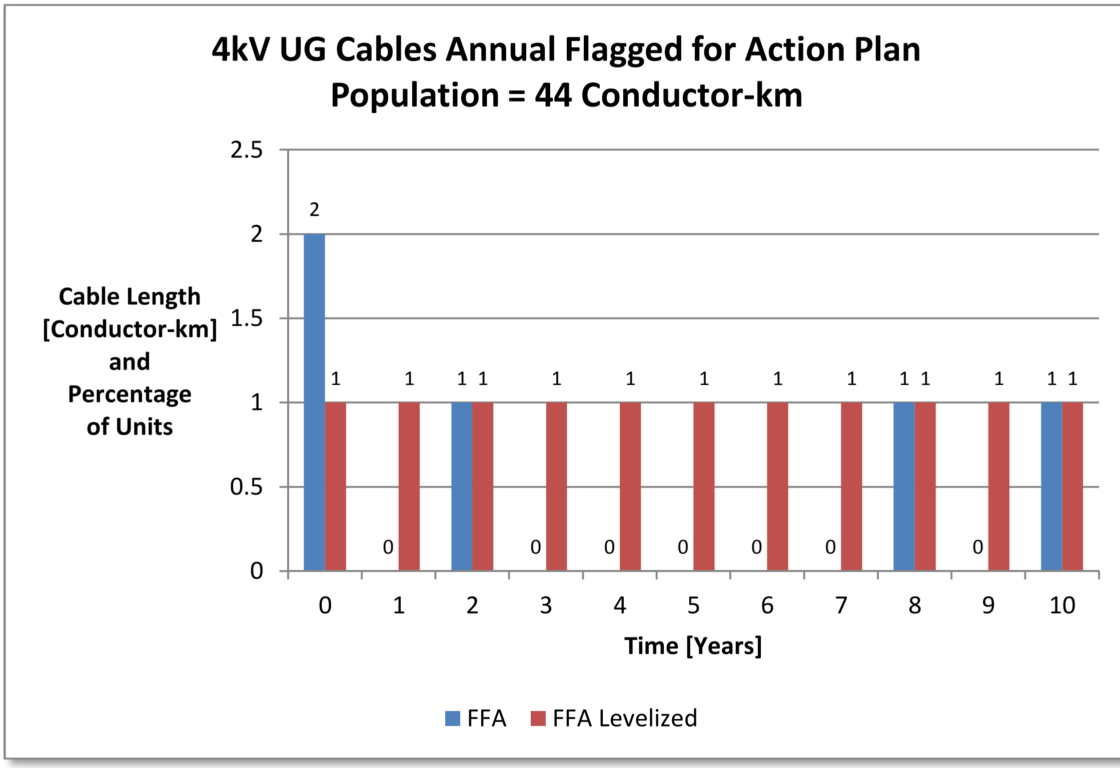

Figure 9-9 4kV Underground Cables Flagged for Action Plan

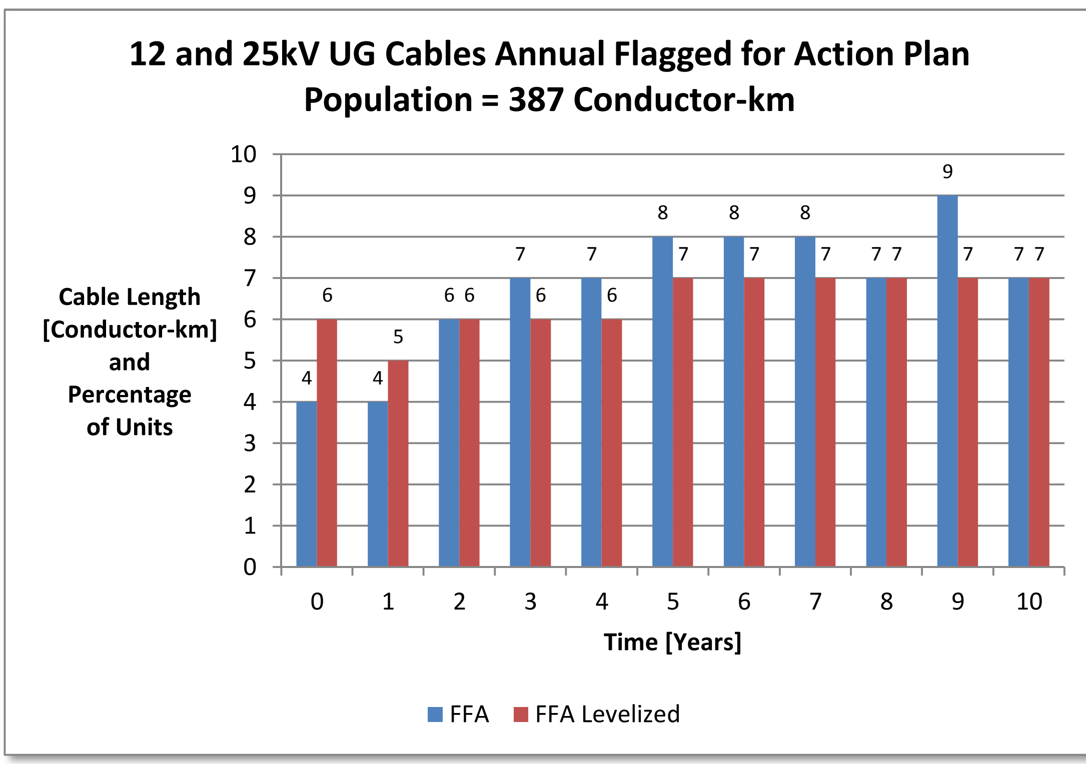

Figure 9-10 12 and 25kV Underground Cables Flagged for Action Plan

9.5 Data Analysis

Age was the only information available for underground cables. Further, as can be seen from the low DAIs of these asset categories, fewer than half of the switches had age information. Age should be collected for the remainder of the population.

Sub-Category	DAI
ALL	48%
4kV	65%
12 and 25 kV	47%

Underground cables had only age information. Further, fewer than half of the cable population had such information. TBH should consider diagnostic testing (e.g. insulation resistance, time domain reflectometry, AC Withstand, PD, Dielectric Spectroscopy/VLF Tan Delta). Such information will provide good, objective condition data as input into the Health Index. Fault information should also be collected.

<table>
<tr><th>Data Gap (Sub-Condition Parameter)</th><th>Parent Condition Parameter</th><th>Priority</th><th>Object or Component Addressed</th><th>Description</th><th>Source of Data</th></tr>
<tr><td rowspan="5">Splice & Termination</td><td rowspan="6">Physical Condition</td><td rowspan="5">★★</td><td rowspan="3">Cable splice</td><td>Under/over-compressed connector</td><td rowspan="5">On-site visual inspection</td></tr>
<tr><td>Improper ground connection</td></tr>
<tr><td>Loose bolt</td></tr>
<tr><td rowspan="2">Cable termination</td><td>Sealing issue</td></tr>
<tr><td>Insulation erosion</td></tr>
<tr><td>Overall</td><td>★★</td><td>Cable segment</td><td>Count of total corrective maintenance work orders issued on cable segment during a specific time window</td><td>Operation record</td></tr>
<tr><td>Cable Tests</td><td>Physical Condition</td><td>★★★</td><td>Cable Overall Condition</td><td>Gross/major defects; weak spots/bulk degradation in insulation; water treeing; localized defects in cable and accessories</td><td>Tests: insulation resistance, time domain reflectometry, AC Withstand, PD, Dielectric Spectroscopy/VLF Tan Delta</td></tr>
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