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September 30, 2024

Ms. Kavita M. Kale
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
P.O. Box 30221
Lansing, MI 48909

Via Electronic Filing

RE: MPSC Case No. U-20147

Dear Ms. Kale:

Pursuant to the Commission's order in the above referenced case, please see and file Alpena Power Company's attached Five-Year Distribution Investment and Maintenance Plan (2024 - 2028). No paper filing is being made.

Please contact me at tmgulden@bfwlawfirm.com if you have questions, and thank you for your assistance.

Sincerely,

Timothy M. Gulden

Digitally signed by Timothy M. Gulden
DN: cn=Timothy M. Gulden, o=Bauer, Florip & Wojda PLC, ou, email=tmgulden@bfwlawfirm.com, c=US
Date: 2024.09.30 11:12:33 -04'00'

Timothy M. Gulden
Attorney for Alpena Power Company

TMG/tsm
Enclosure

2024
Distribution System Plan
U-20147

Alpena Power Company

"First in Service"

1. Executive Summary

On October 10, 1881, the Alpena Electric Light Company, later to become Alpena Power Company, was formed for the "manufacture and production of electricity and electrical lights to supply the City of Alpena and the inhabitants thereof". Today the Alpena Power Company (Alpena or APC or Company) is a private investor-owned Michigan utility with its principal office in the City of Alpena, supplying electric service to approximately 16,700 customers in Alpena, Presque Isle, Montmorency and Alcona counties.

For over the 140 years of its existence, the core principles of Alpena have been to listen to the needs of our customers, deliver on those needs in a reliable, cost-effective, and environmentally responsible manner, while being a community partner to help expand the viability and economic prosperity of the region.

As one of the smallest investor-owned utilities in the state Alpena may not have the means to purchase the technology and systems available to larger utilities but instead its 32 dedicated employees utilize their extensive knowledge of the distribution system, the region, and customers to deliver its investment and maintenance strategy. This plan shows how Alpena is listening to the needs of its customers, has and continues to deliver an investment and maintenance plan that provides reliable, resilient, cost effective, and equitable electric service in an environmentally responsible manner.

On December 22, 2021, the Commission approved a settlement agreement in Case No. U-21045 where the parties to the case agreed that Alpena would work with Staff and file a distribution plan. On September 8, 2022, the Commission ordered Alpena in Case No. U-20147 to file its first distribution investment and maintenance plan by 5:00 p.m. on September 30, 2024. This plan complies with the orders in Case No's U-21045 and U-20147 and is Alpena's first filing of a distribution plan.

2. Distribution Planning Objectives

"The mission of Alpena Power Company is to provide in a responsible and environmentally compatible manner: for our customers, hi quality, low-cost utility services; for our employees, continuing development in a productive workplace; and for our shareholders, a fair rate of return on their investment."

Those words constitute the Mission Statement of Alpena Power Company. Employees strive to operate APC with that mission in the forefront of all decision making. In developing a distribution plan, objectives were drawn from the main points laid out in the Mission Statement to keep the plan aligned with the company's overall vision.

Safety and Environmental Stewardship:

- APC employees prioritize the safety and well-being of co-workers and always promote a participatory safety culture in all business activities. They strive to keep the public safe in the operation of the electric distribution system.
    - This is accomplished through robust construction of facilities, diligent and comprehensive maintenance of lines, structures, and substations, and long-term capital planning.
- APC commits to making moral, environmentally responsible, and fair decisions.
    - All construction and maintenance projects are properly permitted, are compliant with state and federal regulations, and are done with the least amount of impact to property owners as possible. Any damage caused is repaired to as close to original condition as possible.

Efficiency and Reliability Planning

- Every dollar is scrutinized, and every hour is utilized to its fullest extent to ensure APC operations are intentional and productive to keep rates economical for the benefit of customers.
    - This is done through project scoring for priority and risk and careful budgeting of resources.
    - Large projects are spaced between multiple years to lessen the economic impact on the company, and therefore the ratepayers.
- APC implements long-term vision (20-year plan), business strategy, and planning in capital construction and maintenance programs to achieve exceptional reliability, focusing on consistent improvement upon yesterday.

Employee Development and Public Education

- APC believes continuous education helps its employees grow and invests heavily in such programs.
    - A U.S. Department of Labor accredited Apprenticeship Program for Line workers, Substation Technicians, and Meter Workers was recently built by a cross functional group of union and non-union operations employees that utilizes on the job training, as well as online learning modules. These programs are being used not only for our apprentice employees, but also for focused learning objectives for employees in supervision, customer service, and billing.

- APC will always seek opportunities to educate the community on the mission of APC and the hazard of electricity to help build deeper relationships with customers and the public.

Focus on Community Membership and Customer Accessibility and Service

- APC provides an urgent response to any service interruption or customer request, delivering a meaningful and professional experience to the people and community.
    - A customer survey was conducted in 2023. The purpose was to find out what APC customers value and care about the most when it comes to the utility service provided. Feedback from that survey is used in decisions that are made every day and incorporated in this Distribution Plan.
- Technological advancements have been made to provide automated outage management, Interactive Voice Response (IVR), and a customer outage map that is viewable by the public.
    - The goal is to reduce outage times, streamline outage reporting, and increase engagement and information sharing with the public during outage situations.
    - APC's capital plan has a keen eye towards Information System (IS) upgrades and continuous improvement so that customers can feel safe that their data is as protected as possible from cyber-attacks.

3. State of the Utility

3.1. Overview of Service Territory

Alpena's service territory is located in northeast lower Michigan and includes the City of Alpena; the Townships of Alpena, Green, Long Rapids, Maple Ridge, Ossineke, Sanborn, Wellington and Wilson in the County of Alpena; the Township of Presque Isle in Presque Isle Conty; The Township of Caledonia in Alcona County; and the Village of Hillman and Township of Hillman in Montmorency County.

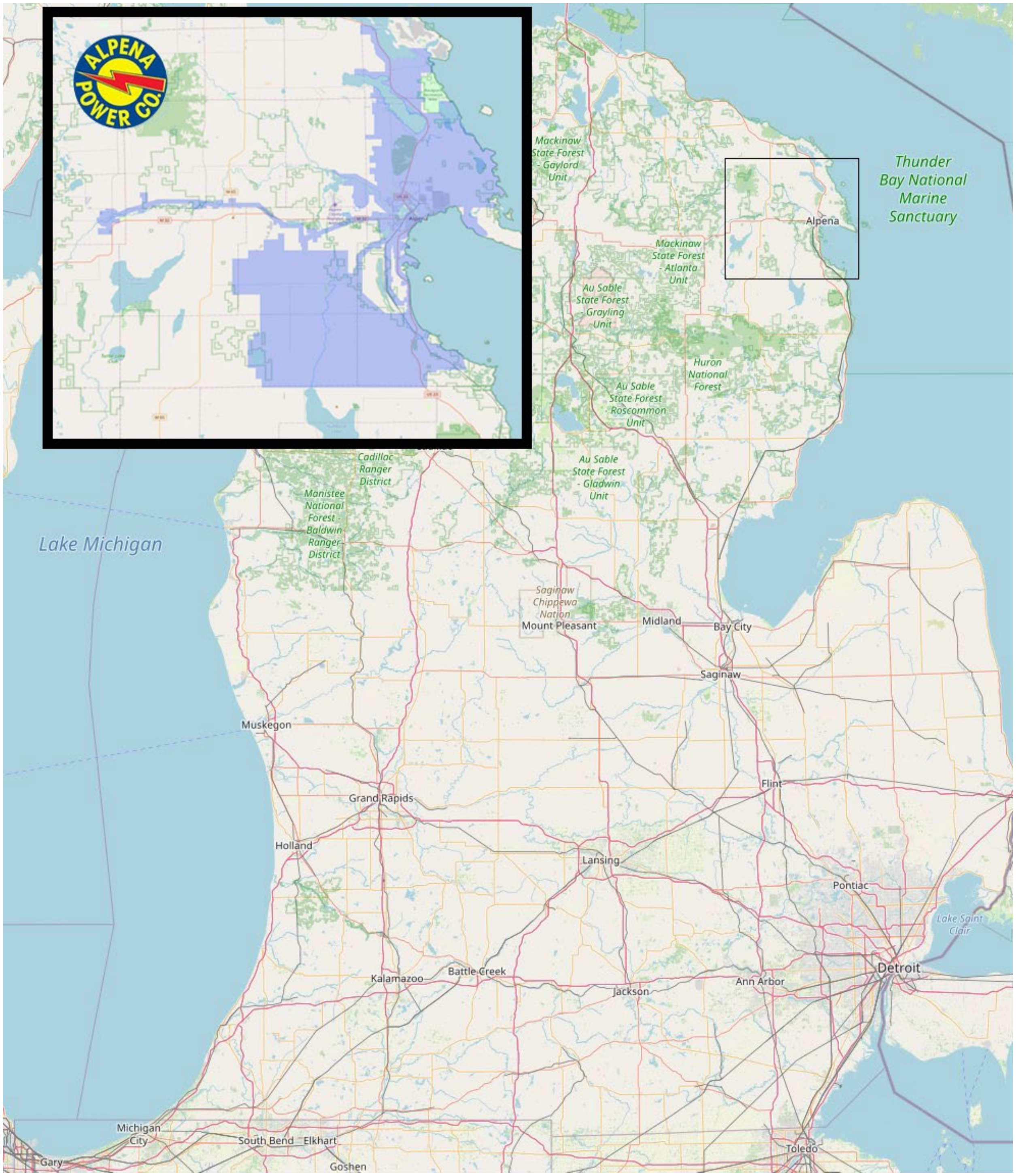

Figure 1: Alpena Power Company Service Territory

Alpena's service territory includes approximately 61 miles of Lake Huron shoreline and covers approximately 250 square miles. Much of the shoreline and northern portions of the territory consists of low, wet, and rocky terrain while the southwest portion is a mix of farm and forest land.

The wetland areas can cause significant access issues for maintenance and construction activities and play a role in the distribution planning process. As documented by Michigan Department of Environment, Great Lakes, and Energy (EGLE)[1] much of Alpena's service territory is impacted by wetlands which requires permitting and access to be incorporated to the planning process.

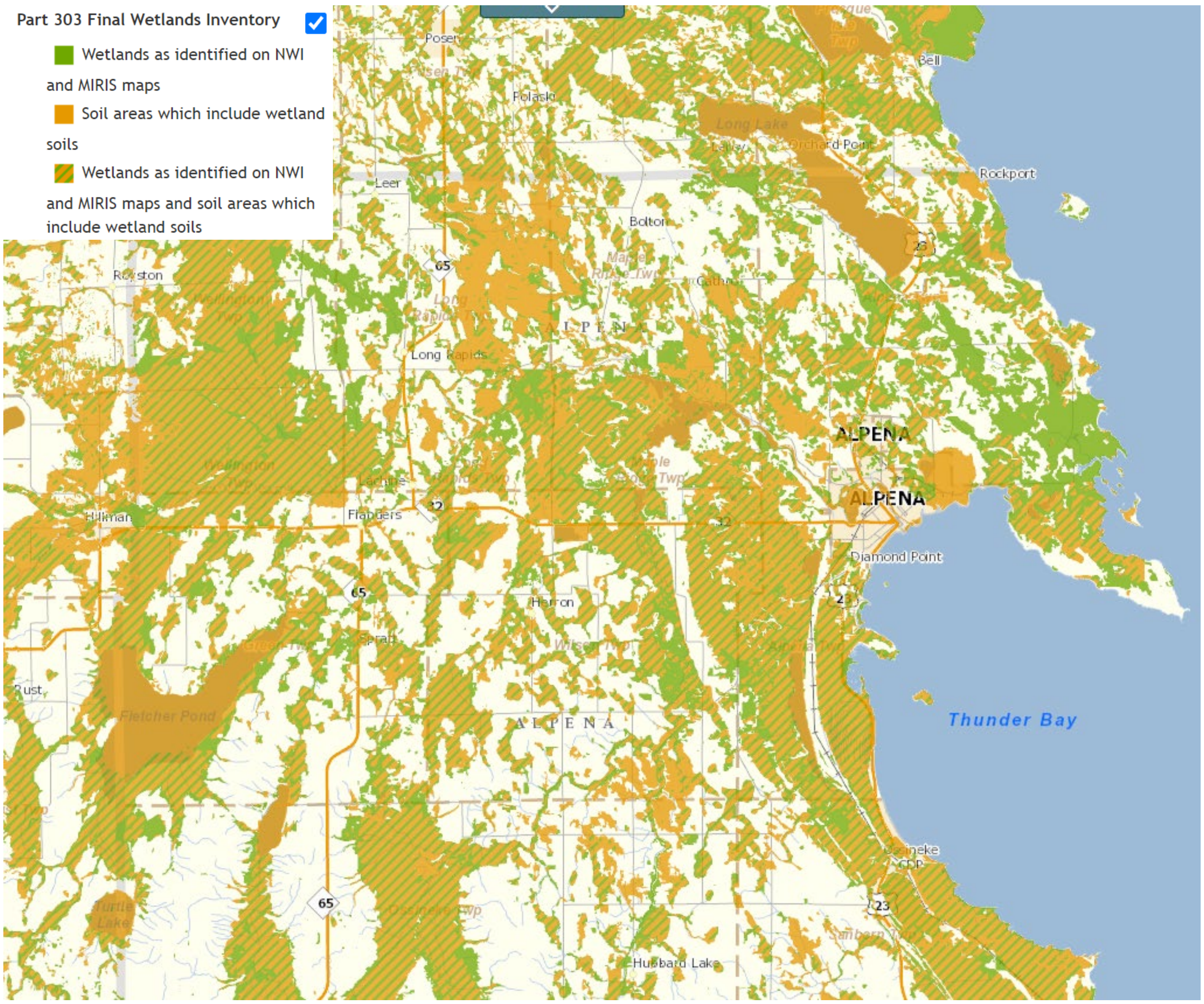

Figure 2: EGLE Wetland Map

High tree density in the service territory can be a challenge for distribution planning and impacts reliability. According to data published by the Michigan Department of Natural

[1] https://www.michigan.gov/egle/maps-data/wetlands-map-viewer

Resources (DNR)[2] much of Alpena's service territory is considered "Woody Wetland" with a forest cover range of 69.6% to 75.1% as shown in Figures 3 and 4 below.

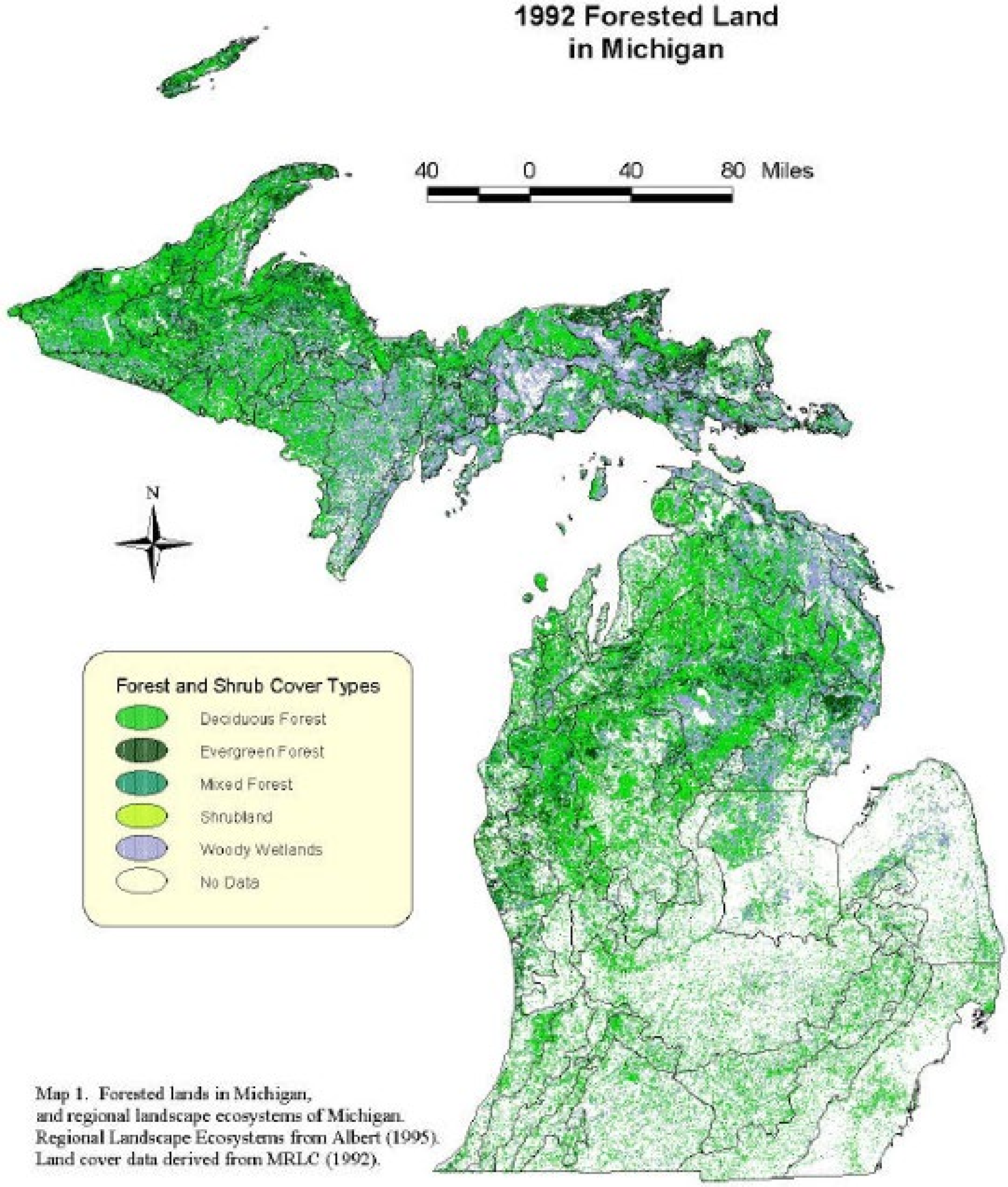

Figure 3: Forest Land in Michigan

[2] https://www.michigan.gov/-/media/Project/Websites/dnr/Documents/FRD/SFMP/13overview.pdf?rev=44d9b8f272cb439ca62540b650ba5ba9

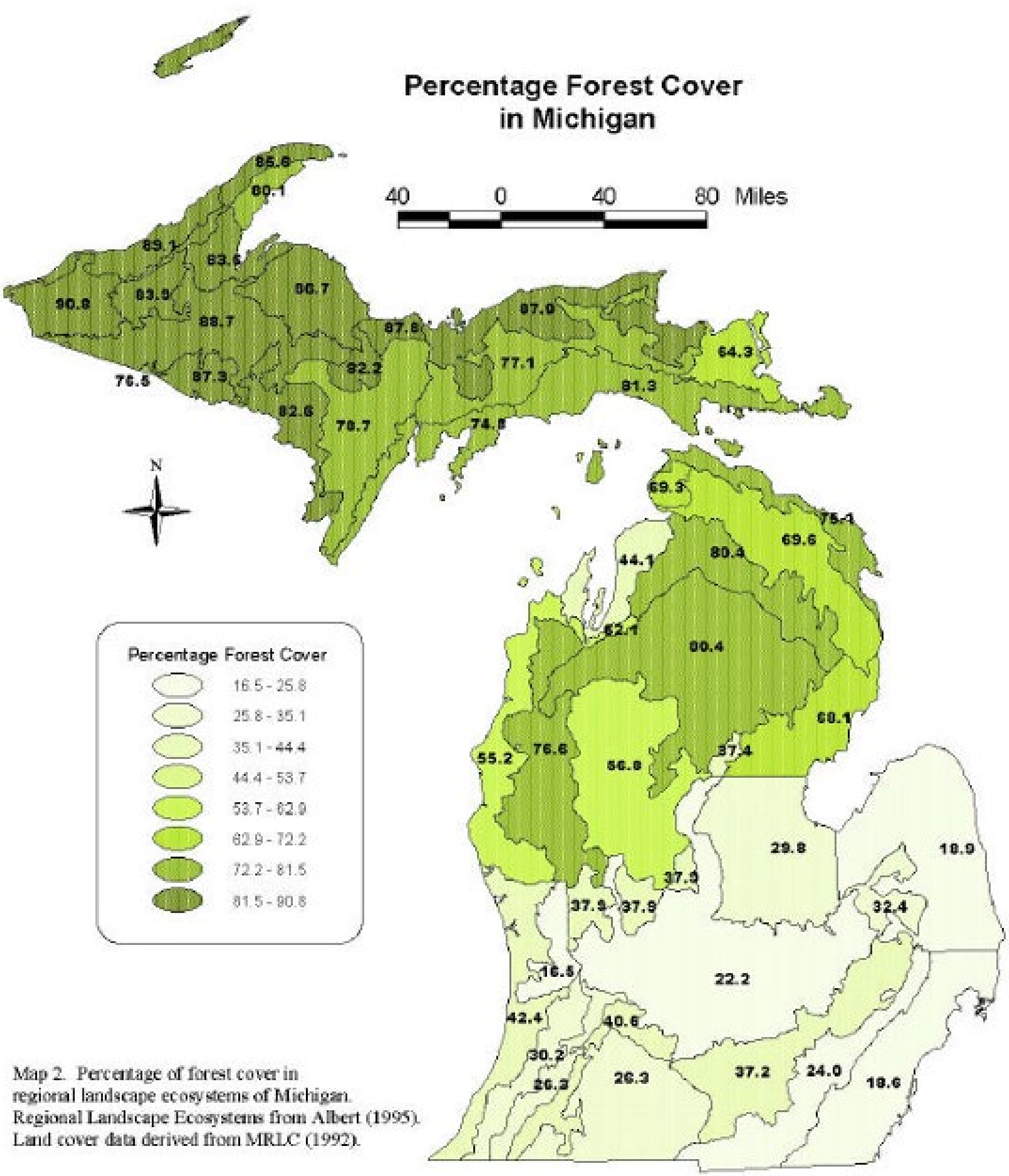

Figure 4: Percentage Forest Cover in Michigan

3.2. Customer Engagement and Feedback

In summer 2023 Alpena sent a 10-question survey to its approximately 16,650 customers to get feedback on Alpena's reliability, rates, customer interaction, and overall performance. The survey was promoted through Alpena's website, social media, and a bill insert. Alpena received 915 responses which is approximately a 5.5% response rate.

Question 1: Which one of the following applies? I am an Alpena Power Company:

Answer Choices	Responses
Residential Customer	96.4%
Commercial Customer	3.5%
Industrial Customer	0.0%
Not a Customer	0.1%

Question 2: What are the most effective ways of communicating with you? (Check all that apply)

Answer Choices	Responses
Billing Insert	76.8%
Email	32.9%
Text Messaging	26.5%
Newspaper	18.0%
In Person	16.4%
Television	11.1%
Radio	9.4%
APC Website	4.8%
Social Media	4.8%
None	0.9%

Question 3: In order of importance, please rank the following priorities for Alpena Power. (1 being most important)

	1	2	3	4	5	Weighted Average
Reliability (keeping the lights on)	79.4%	14.8%	3.8%	1.0%	1.1%	1.30
Cost of providing utility service	19.2%	61.2%	14.2%	3.2%	2.2%	2.08
Environmental responsibility	3.9%	12.5%	41.7%	22.4%	19.5%	3.41
Customer engagement to manage my energy usage and customer bills	2.4%	6.3%	28.9%	43.4%	19.0%	3.70
Alpena Power's engagement with the community	3.9%	4.3%	11.0%	27.3%	53.6%	4.22

Question 4: For all of 2022 the average Alpena Power customer lost their power less than twice and was without power for a total of 160 minutes throughout the year. I feel this level of service is:

Answer Choices	Responses
Excellent	48.5%
Above Average	38.3%
Average	12.2%
Below Average	0.9%
Poor	0.1%

Question 5: The average APC residential customer's bill is about $75 a month, I feel this cost for electricity is:

Answer Choices	Responses
Excessive	2.4%
Higher than it should be	19.8%
Reasonable	72.9%
Lower than average	2.5%
A bargain	2.3%

Question 6: Please check which answer best describes how I feel APC should manage reliability and cost.

Answer Choices	Responses
I am willing to pay significantly more for power if it means significantly better reliability	0.9%
I am willing to pay a little more for power if my reliability improves	5.9%
I think the balance between cost and reliability is where it should be	85.4%
My power bill is already too high, I am ok with more outages if my bill is lower	4.8%
My power bill is excessive, APC should do everything it can to lower costs even if it means many more outages	3.0%

Question 7: Most outages are caused by trees falling into power lines, from wind during storms or from the weight of snow and ice, please check which answer best describes how I feel Alpena Power should manage its tree trimming program.

Answer Choices	Responses
APC should do as little trimming as possible, even if it means I may lose power more often	1.5%
APC should find other ways to deliver power to avoid trimming trees, even if it means higher customer bills	2.6%
The balance between tree trimming and reliability is where it should be	54.1%
APC should be more aggressive trimming and clearing trees to improve reliability	25.0%
APC should cut as many as it needs to provide reliable power	16.9%

Question 8: APC purchases 100% of its customer's energy needs. In order of importance, please rank where you feel your energy should come from in the future (1 being most important)

	1	2	3	4	5	6	Weighted Average
Renewable sources (hydro, solar, wind, biomass)	44.6%	11.6%	10.9%	6.4%	10.5%	16.0%	2.75
Coal-fired generators	5.1%	8.0%	13.7%	19.7%	26.5%	27.2%	4.36
Natural-gas fired generators	21.5%	24.3%	26.2%	18.5%	8.0%	1.6%	2.72
Nuclear Power	9.2%	16.0%	15.8%	16.0%	16.9%	25.9%	3.93
A balance portfolio	44.5%	19.7%	14.4%	13.3%	6.8%	1.3%	2.22
Lowest cost portfolio	25.7%	17.3%	12.2%	13.0%	17.5%	14.3%	3.22

Question 9: Compared to other large utilities in the state, APC offers less rate and technology options for customers to manage their energy usage. Please check which rate and technology options you would like to be available.

Answer Choices	Responses
Smart meters	23.5%
Time of use rates	16.4%
Real time pricing	9.8%
Demand response programs	4.3%
No changes	57.4%

Question 10: Overall, I feel APC's performance as a utility is:

Answer Choices	Responses
Excellent	39.6%
Above Average	42.3%
Average	14.6%
Below Average	0.3%
Poor	0.2%

The Company's review of the survey results demonstrated that its customers value reliability, the cost of providing service, and environmental responsibility in that order. The customers also indicated they are satisfied with APC's rate and program offerings, customer interaction, and Alpena's overall performance as a utility.

Other ways Alpena engages with its customers include a biannual newsletter the Company sends all customers as a bill insert which highlights ongoing maintenance and large capital investment projects such as vegetation management areas and timing and line rebuild projects or substation projects, press releases, social media posts, and community group discussions.

3.3. Reliability Analysis

3.3.1. Reliability Standards Overview

Significant emphasis has been placed on reliability reporting, specifically standardizing reliability reporting, in the State in the past few years. Along with this trend, Alpena performed complete review of its reporting in 2022 and invested in its first ever outage management system to not only improve its response to outages but also its reporting.

There were three major changes in Alpena's reporting due to the 2022 review. First had to do with outage causes. Prior to 2022 Alpena reported causes based on initiating cause, meaning if a weather event caused a tree to fall into the power line the outage cause would be weather, as it initiated the tree to fall. Beginning in 2022 Alpena adopted IEEE Standard 1782-2022 which categorizes outages by their sustaining cause.

For example, a tree falls on a windy day and contacts the primary overhead wires. In this instance, the initiating cause would be weather but the sustained cause that the outage would be categorized by is trees. Another example would be during a winter storm heavy snow and ice causes a large tree branch to fall into primary wires, and in the process the weight on the wires causes a nearby utility pole to break and fall to the ground. While the initiating cause is weather, the sustaining, and categorized cause, is equipment failure.

The second major change deals with major events days and catastrophic events. Prior to 2022 Alpena did not calculate Major Event Days (MED) per IEEE Standard 1366 but instead utilized the MPSC definition of catastrophic events, outage event for 10% or more customers, as major event days. The result likely categorized less outages as major events as the MED threshold is typically less than 10% of Alpena's customer base. Starting in 2023 Alpena calculates MED per IEEE 1366 and tracks catastrophic events per the MPSC definition.

The third major change has to do with events outside of the Company's control, such as vehicle accidents or outages caused by other utilities. Per the revised Service Quality Rules and guidance in Case No. U-12270, major system failures due to accidents and outages caused by other utilities are exempt from the standards and not included in the Company's reliability indices starting in 2023.

3.3.2. Reliability Indices

Alpena has tracked the System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Customer Average Interruption Duration Index (CAIDI), without catastrophic conditions going back to 1991 and with catastrophic conditions going back to 2006. These indices are as defined per The Institute of Electrical and Electronics Engineers (IEEE) Standard 1366.

- **SAIFI** is the total number of customer interruptions divided by the number of customers served.
- **SAIDI** is the total minutes of interruptions divided by the number of customers served.
- **CAIDI** is the total minutes of interruptions divided by the total number of customer interruptions.

The historical performance for the past 30 years excluding Major Storms and 18 years including major storms is summarized in the graphs below.

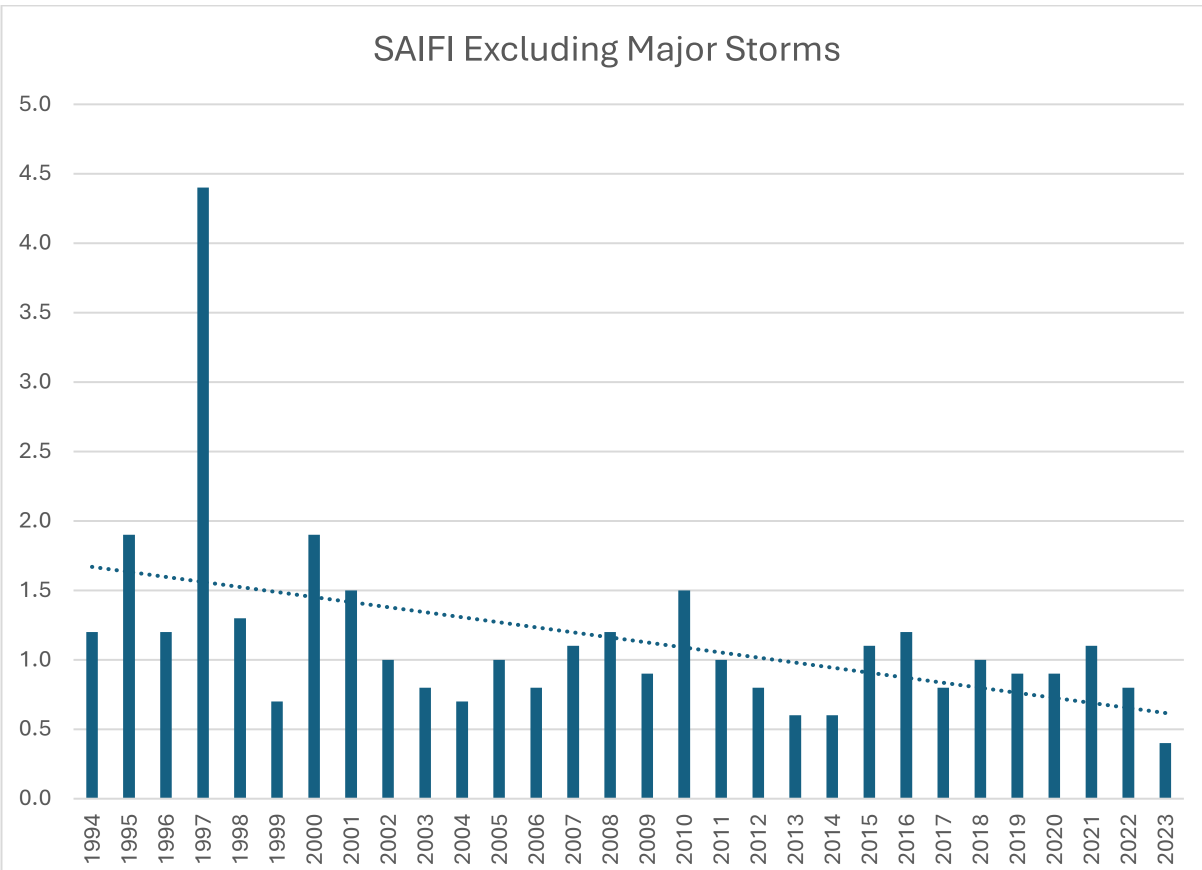

Figure 5: SAIFI Excluding Major Storms Historical Performance

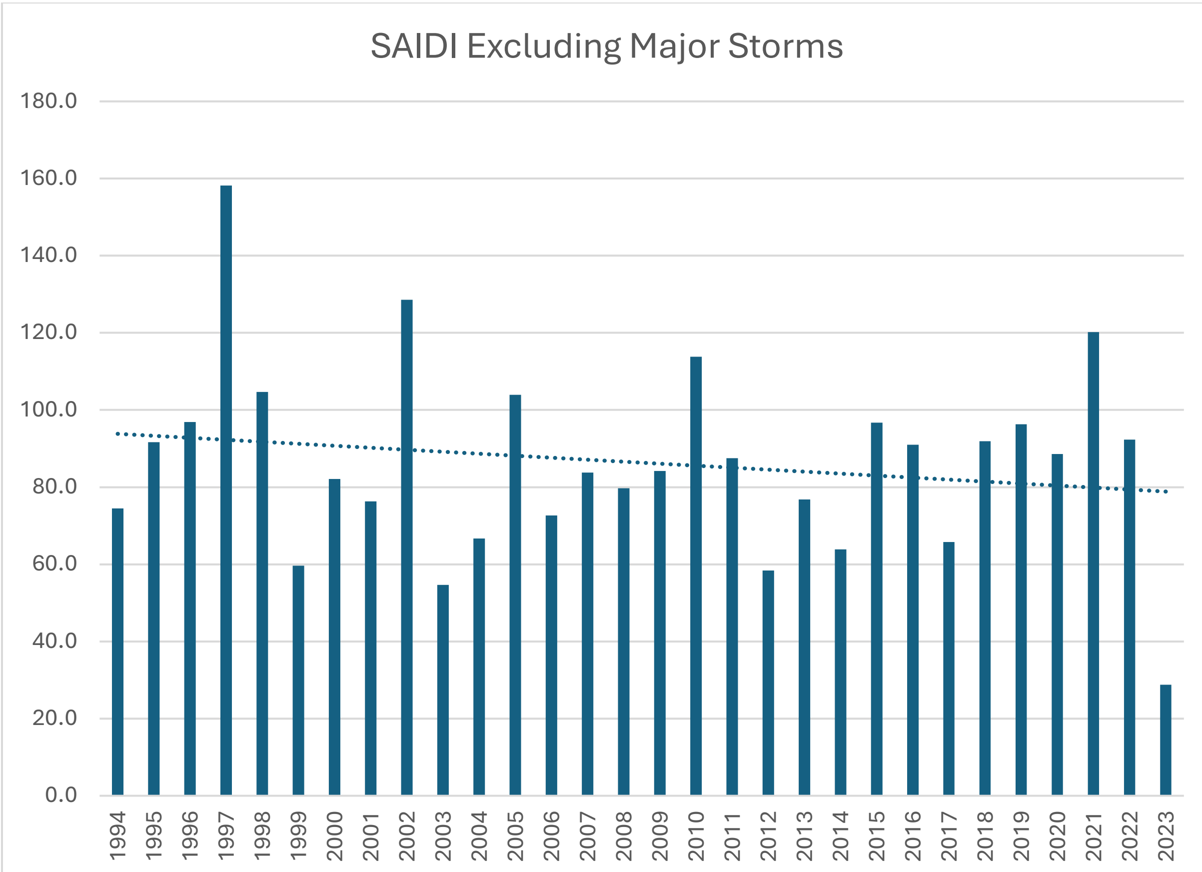

Figure 6: SAIDI Excluding Major Storms Historical Performance

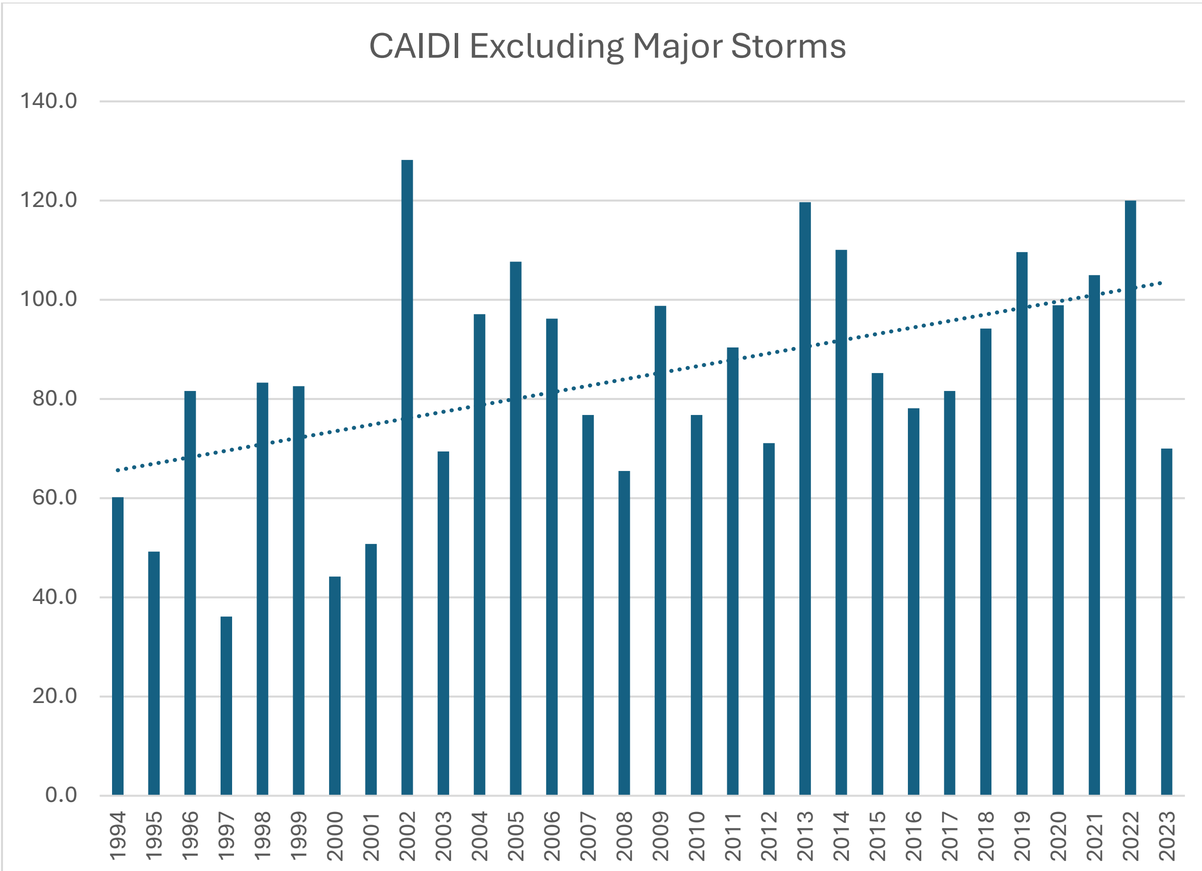

Figure 7: CAIDI Excluding Major Storms Historical Performance

Over the past 30 years Alpena's performance for SAIFI and SAIDI excluding major storms has steadily improved while CAIDI excluding major storms has increased. The improved SAIFI and SAIDI can be linked to Alpena's maintenance and investment plans while the reasons for increasing CAIDI are more difficult to identify. Some causes being investigated include the larger amount of underground distribution, while underground has less outage incidents repairs are typically longer in duration than overhead. Another possible cause is forest health issues, such as the emerald ash borer or oak wilt, causing mature trees located outside of the right of way to die and fall causing more damage and equipment failures.

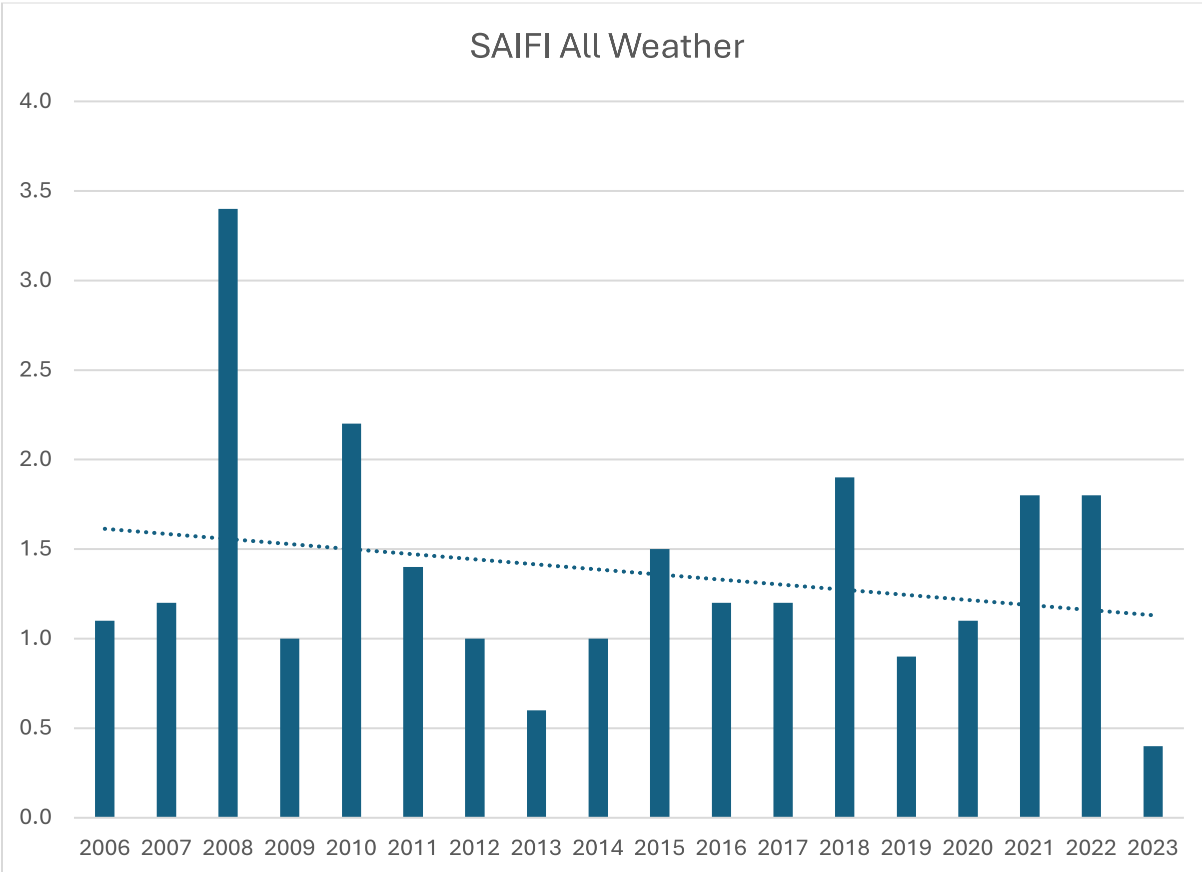

Figure 8: SAIFI All Weather Historical Performance

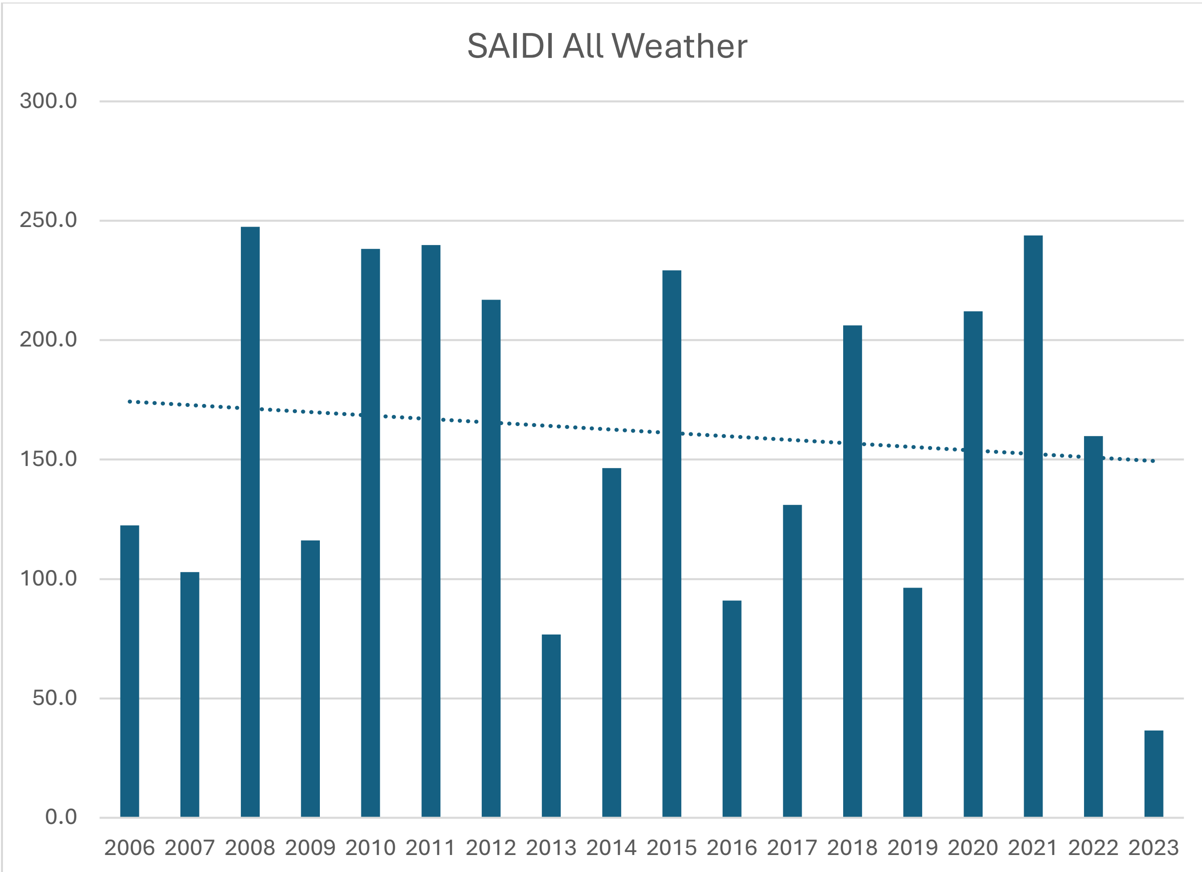

Figure 9: SAIFI All Weather

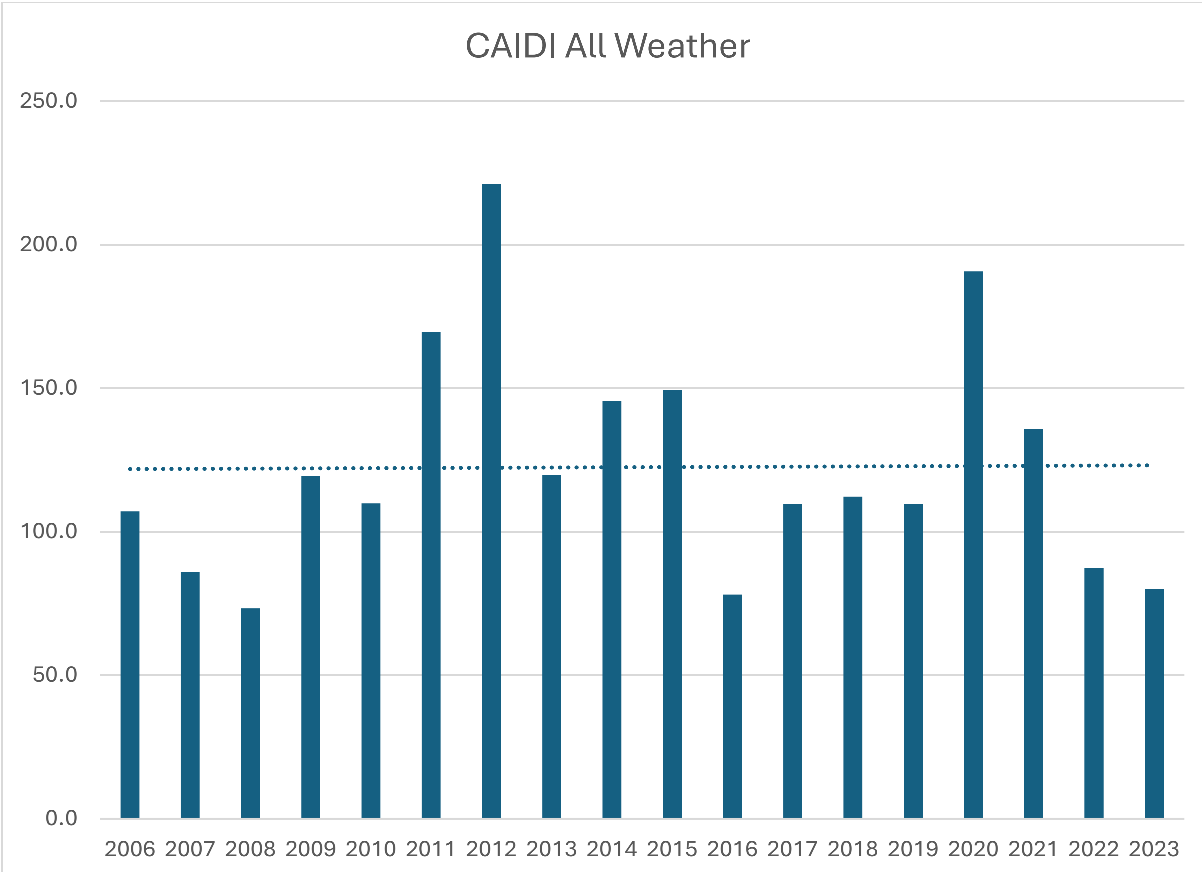

Figure 10: CAIDI All Weather

Alpena's reliability performance for SAIFI and SAIDI in all-weather situations have been on a declining trend similar to the same indices excluding MED. CAIDI all weather has been relatively flat illustrating Alpena continued performance during major weather events.

3.3.3. Reliability Comparison to Other Utilities

In the December 21, 2023, order in Case No. U-12270[3] the Commission ordered each electric utility and cooperative to file an annual report, using the Commission ordered template, summarizing reliability performance. The 2023- and five-year averages for SAIFI, SAIDI, and CAIDI for all Investor-Owned Utilities (IOU) and Cooperatives are summarized in the following charts.

[3] https://mi-psc.my.site.com/s/case/500t0000008eeRgAAI/in-the-matter-on-the-commissions-own-motion-of-the-investigation-into-the-methods-to-improve-the-reliability-of-electric-service-in-michigan

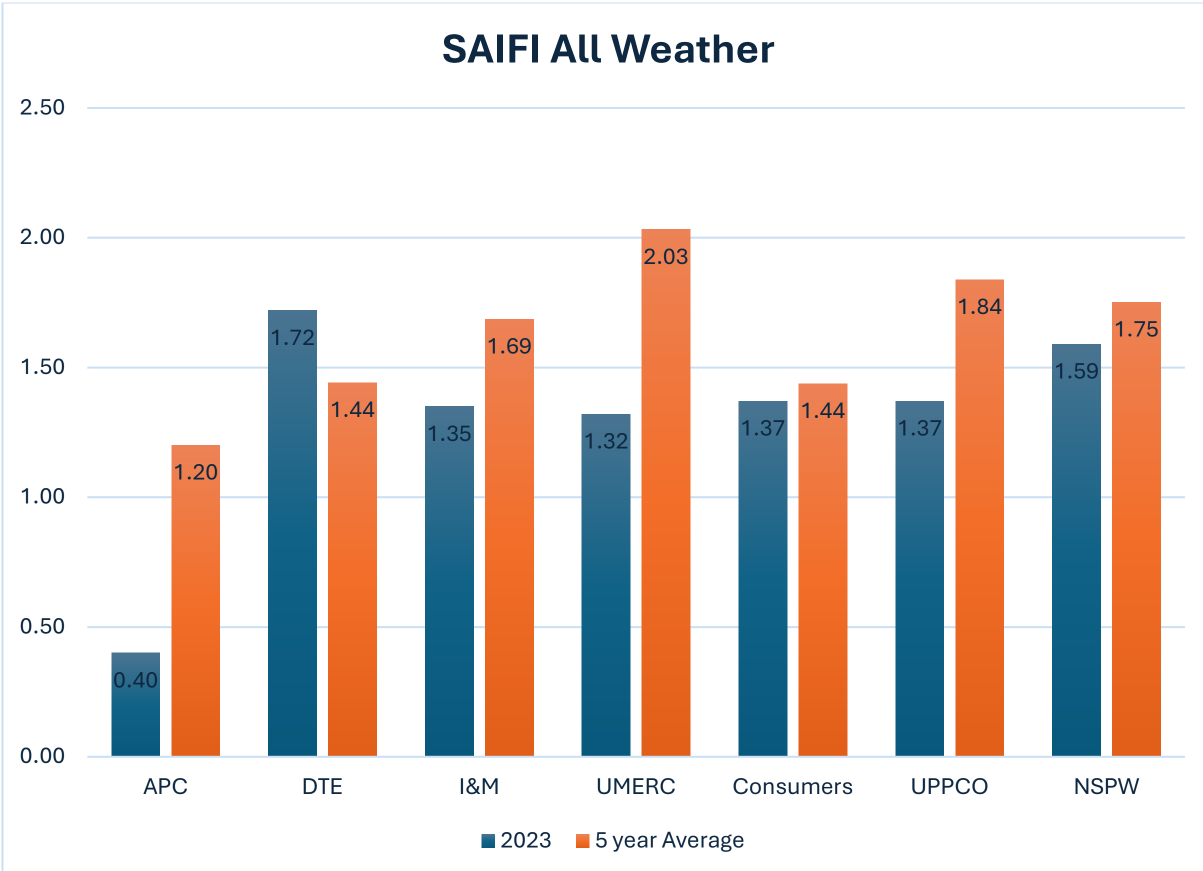

Figure 11: SAIFI All Weather – IOUs

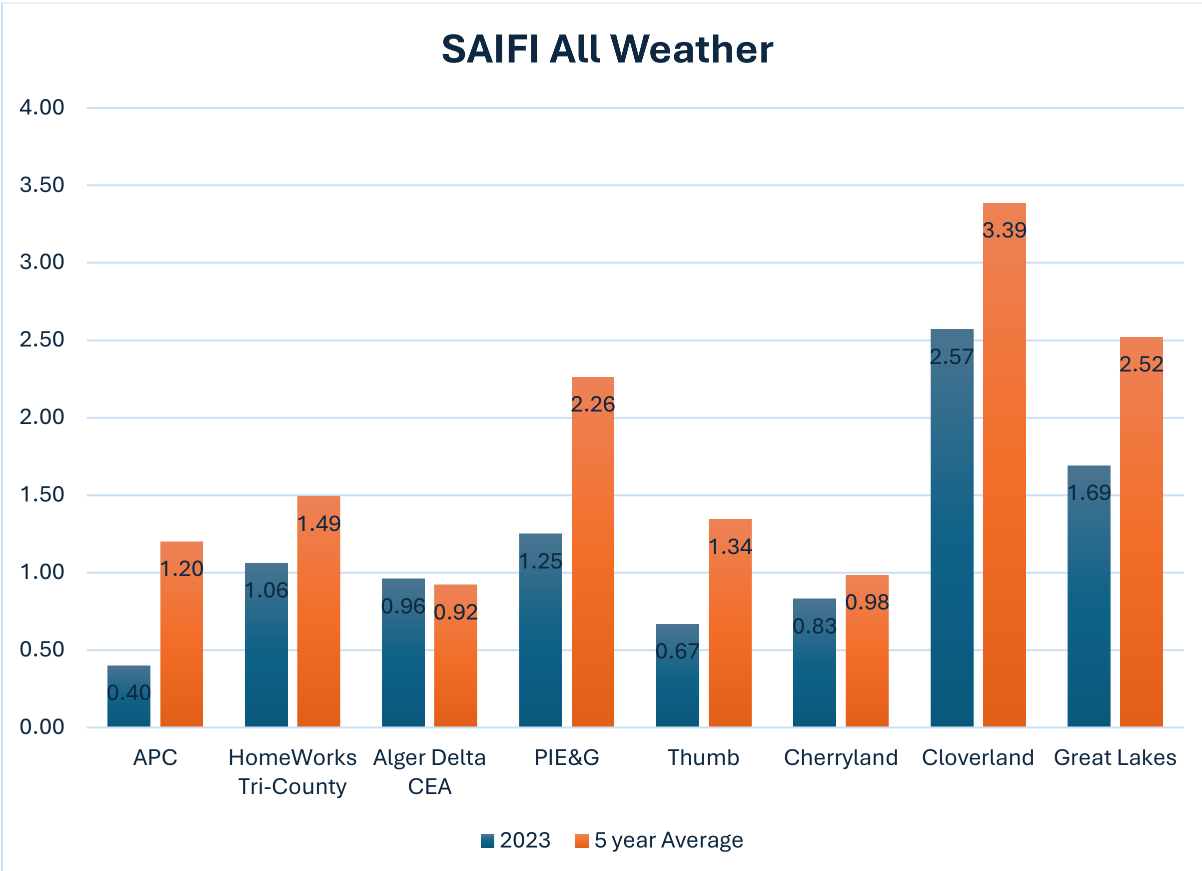

Figure 12: SAIFI All Weather – Cooperatives

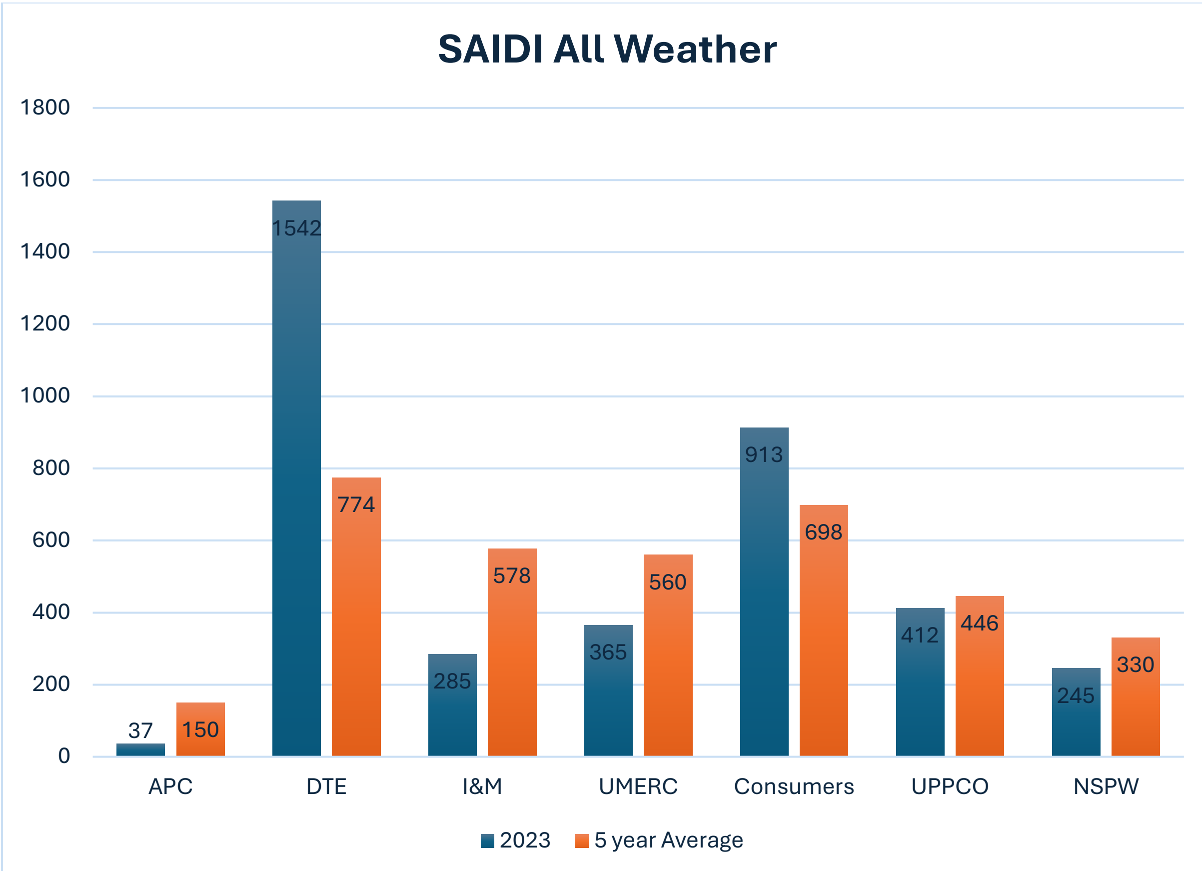

Figure 13: SAIDI All Weather – IOUs

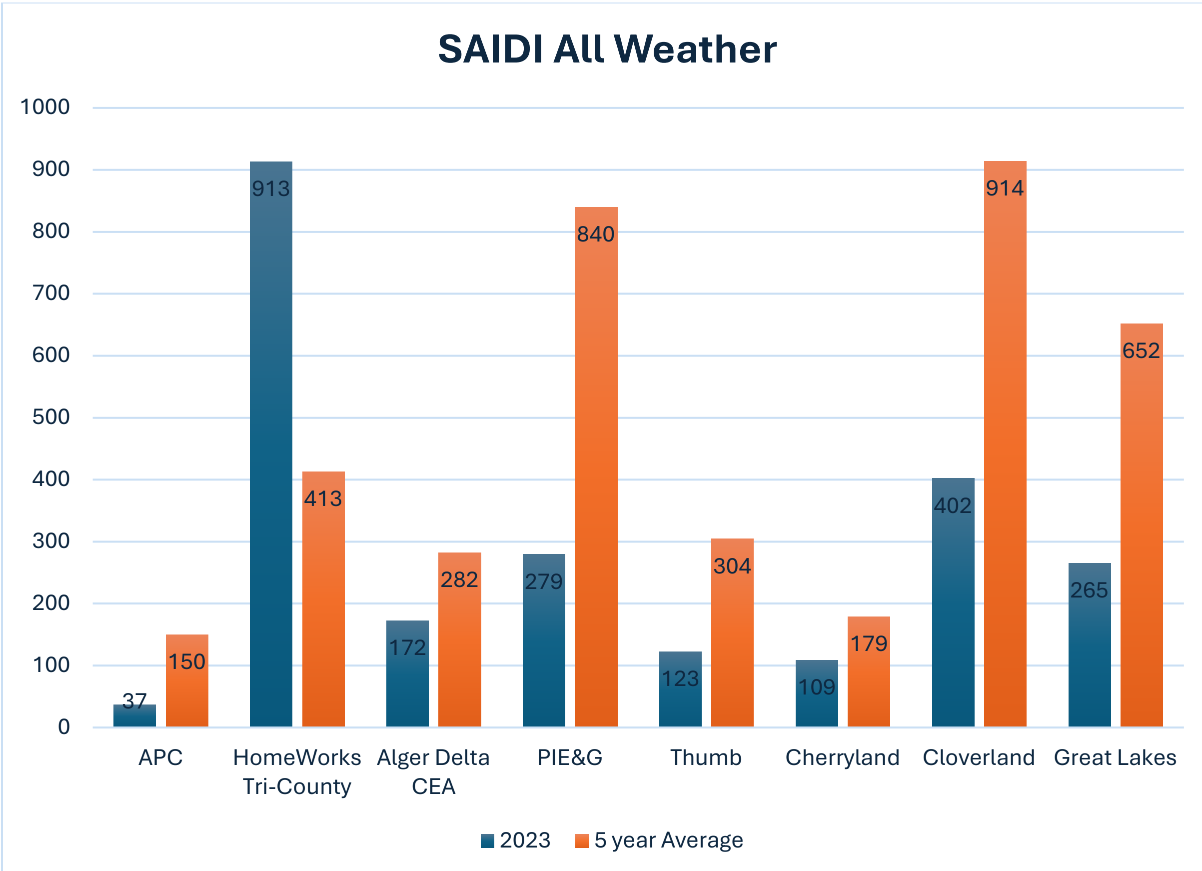

Figure 14: SAIDI All Weather - Cooperatives

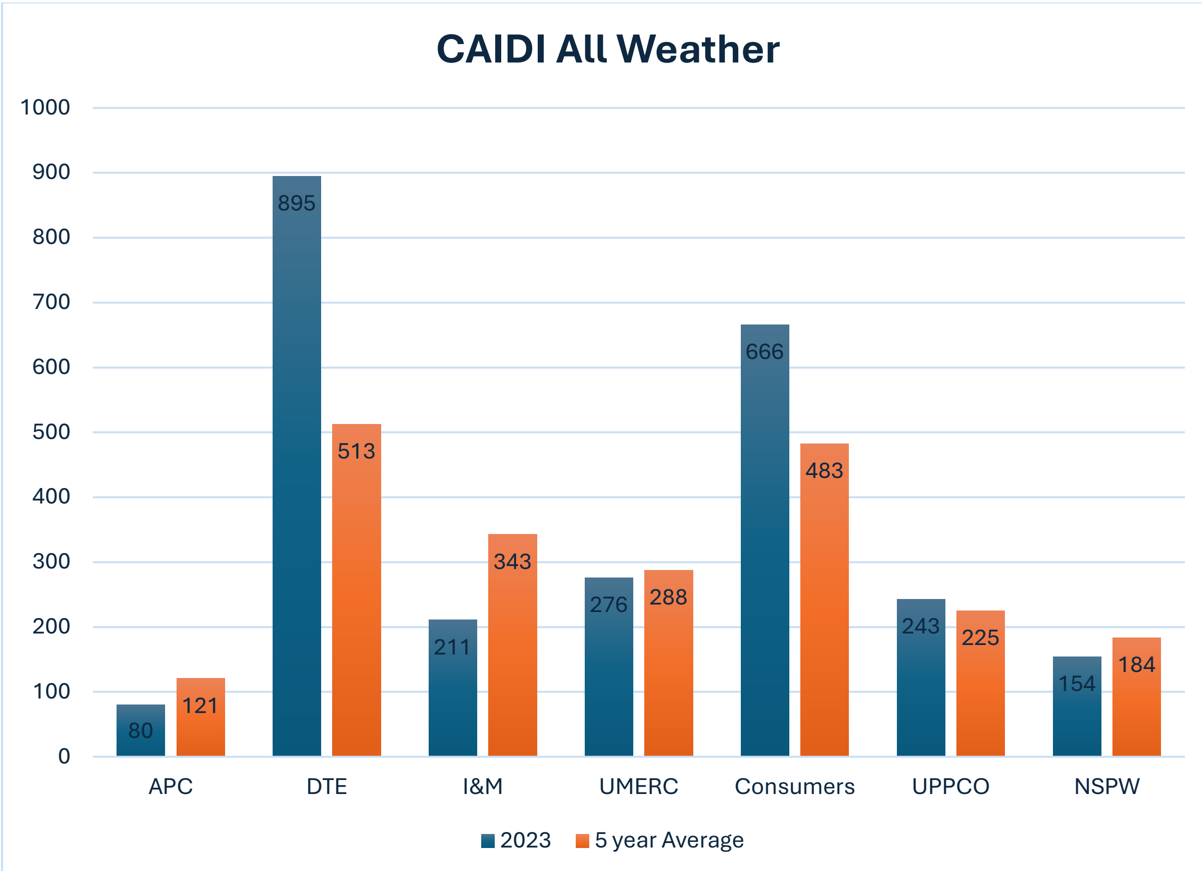

Figure 15: CAIDI All Weather – IOUs

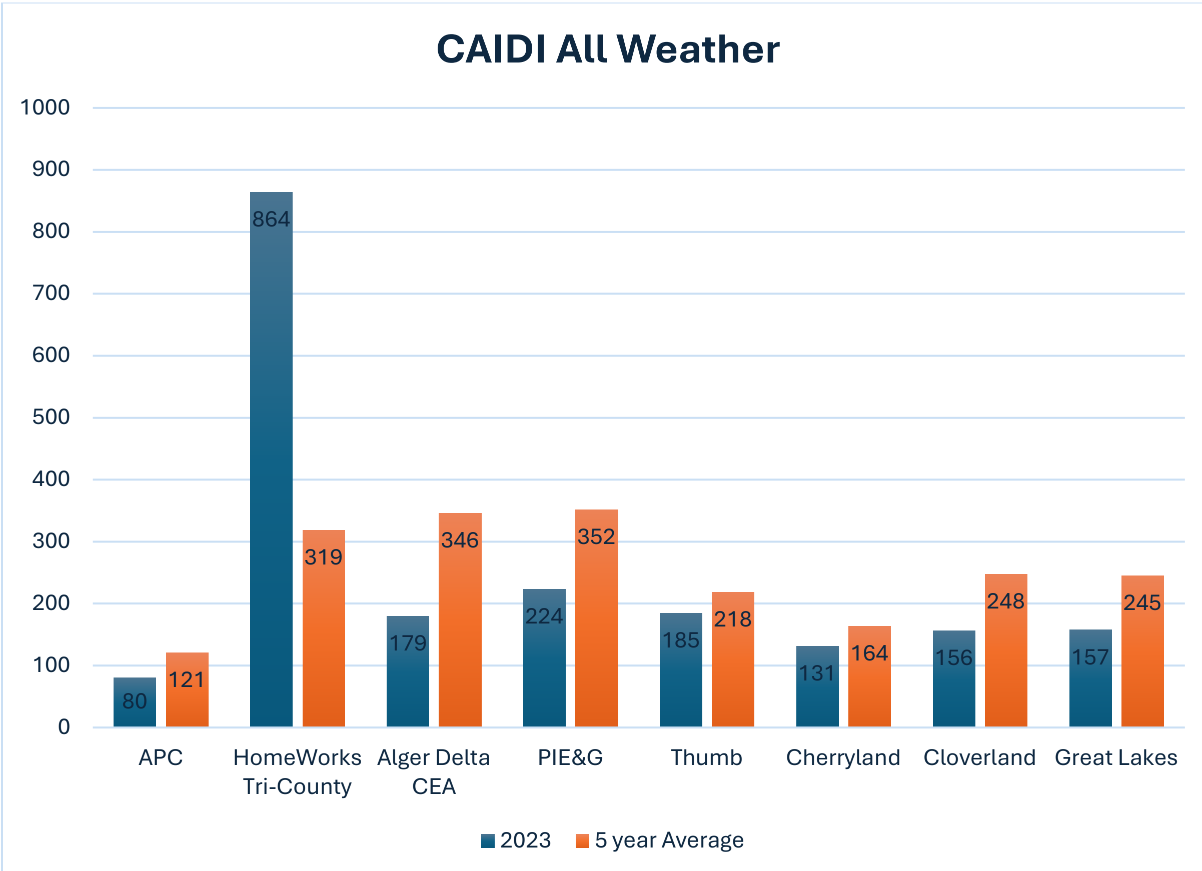

Figure 16: CAIDI All Weather – Cooperatives

Alpena's 2023 and five-year average results for SAIDI all weather and CAIDI all weather are lowest among the fourteen investor-owned utilities and cooperatives. Alpena's 2023 SAIFI all weather is lowest among the fourteen utilities and five-year average is third behind Alger Delta and Cherryland.

3.3.4. Reliability Comparison to IEEE Benchmarks

On its website, the Commission posts Distribution System Reliability Metrics[4] that compare each utilities reliability metrics for SAIDI, SAIFI, and CAIDI both excluding MED and All Weather to the IEEE Quartile Benchmarks.

[4] https://www.michigan.gov/mpsc/consumer/electricity/distribution-system-reliability-metrics

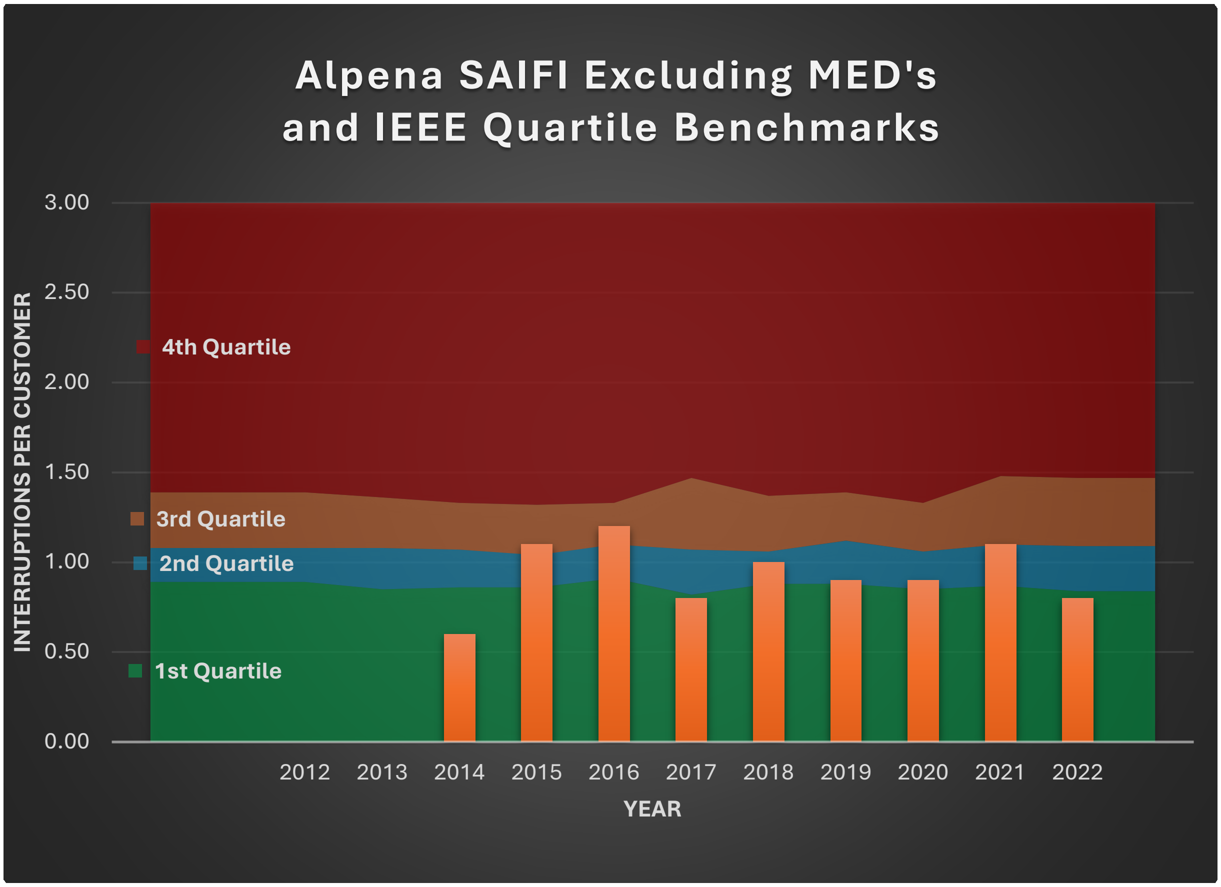

Figure 17: SAIFI Excluding MED and IEEE Quartile

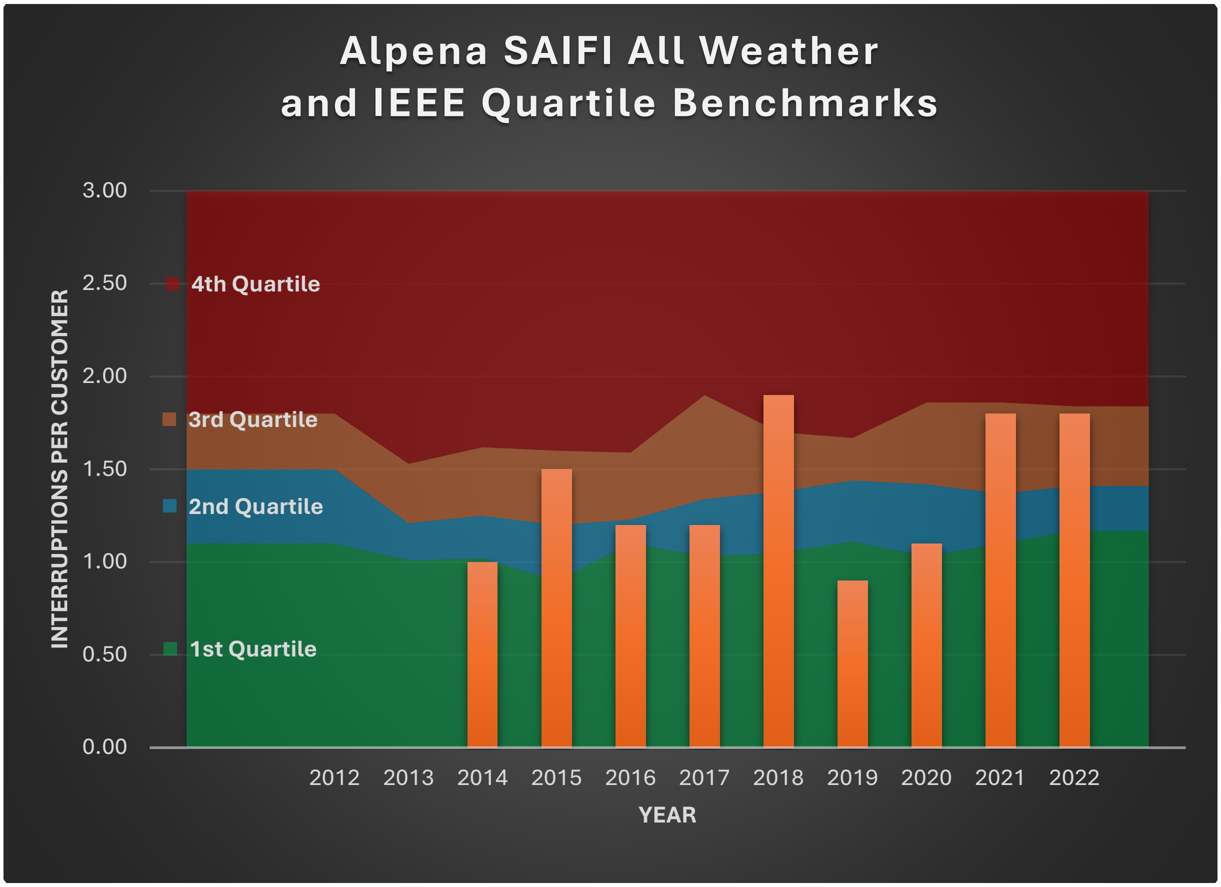

Figure 18: SAIFI All Weather and IEEE Quartile

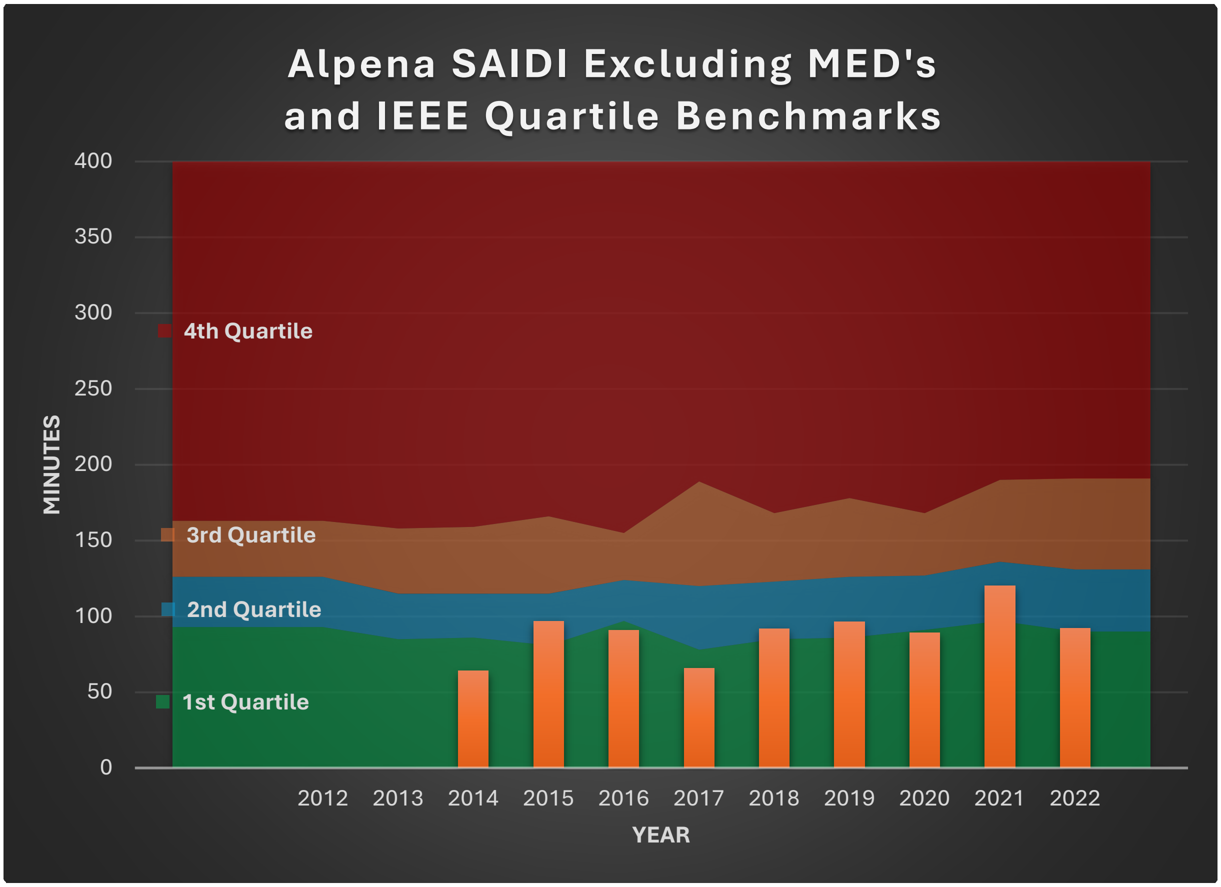

Figure 19: SAIDI Excluding MED and IEEE Quartile

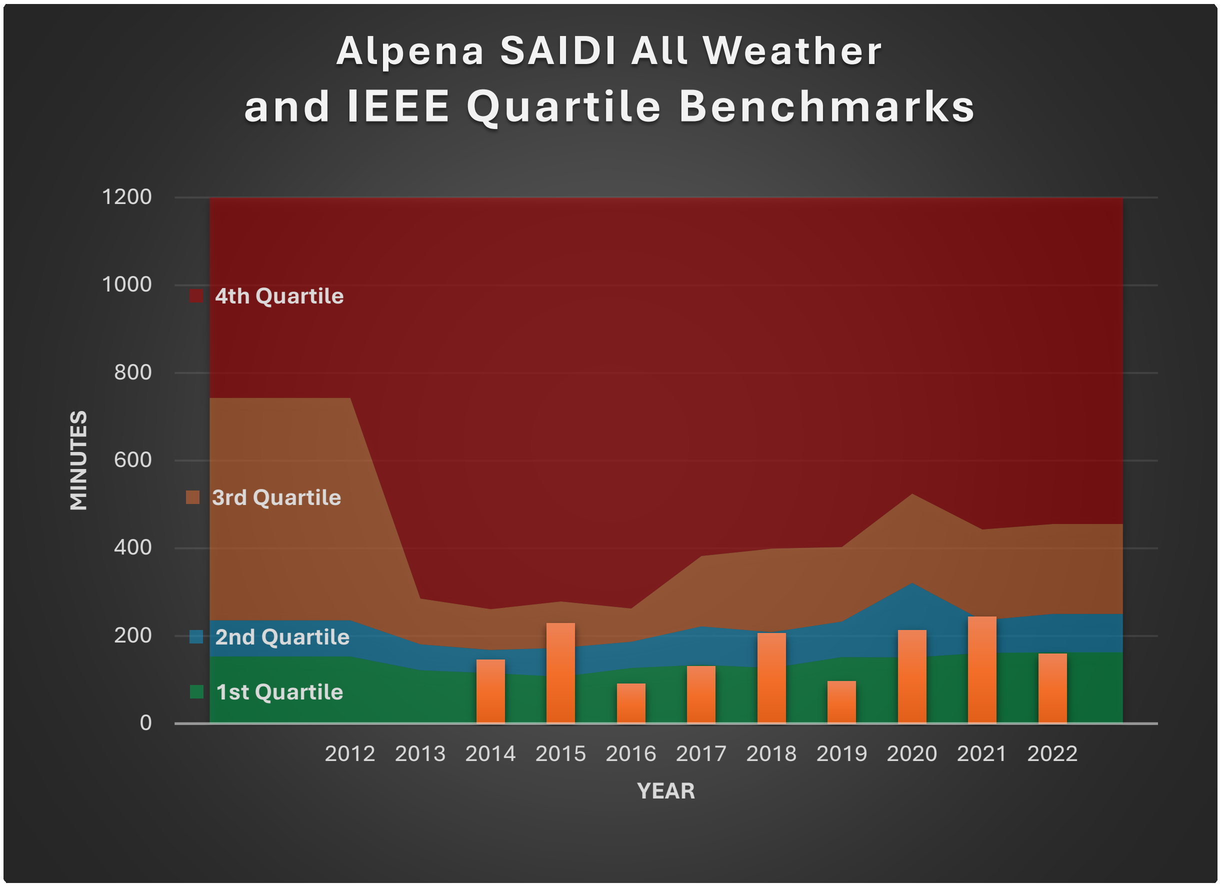

Figure 20: SAIDI All Weather and IEEE Quartile

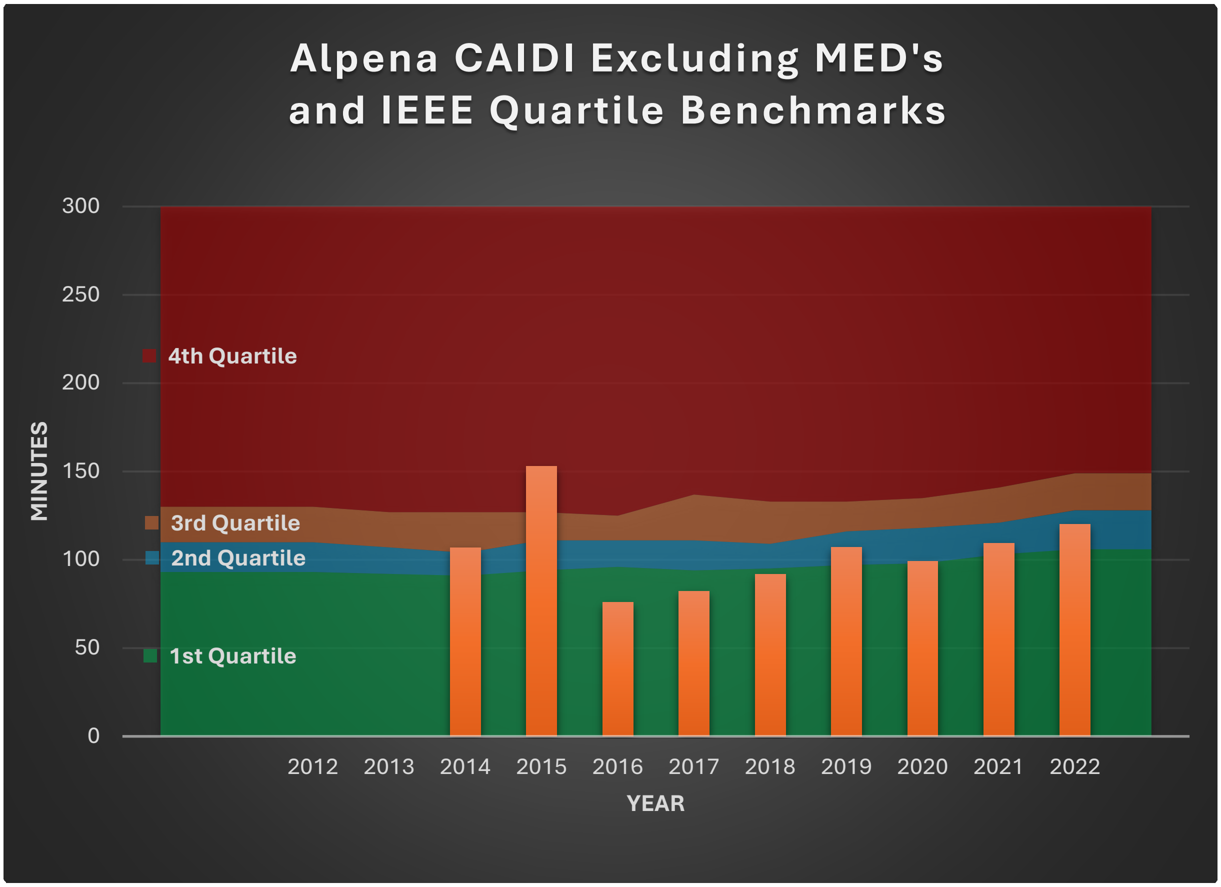

Figure 21: CAIDI Excluding MED and IEEE Quartile

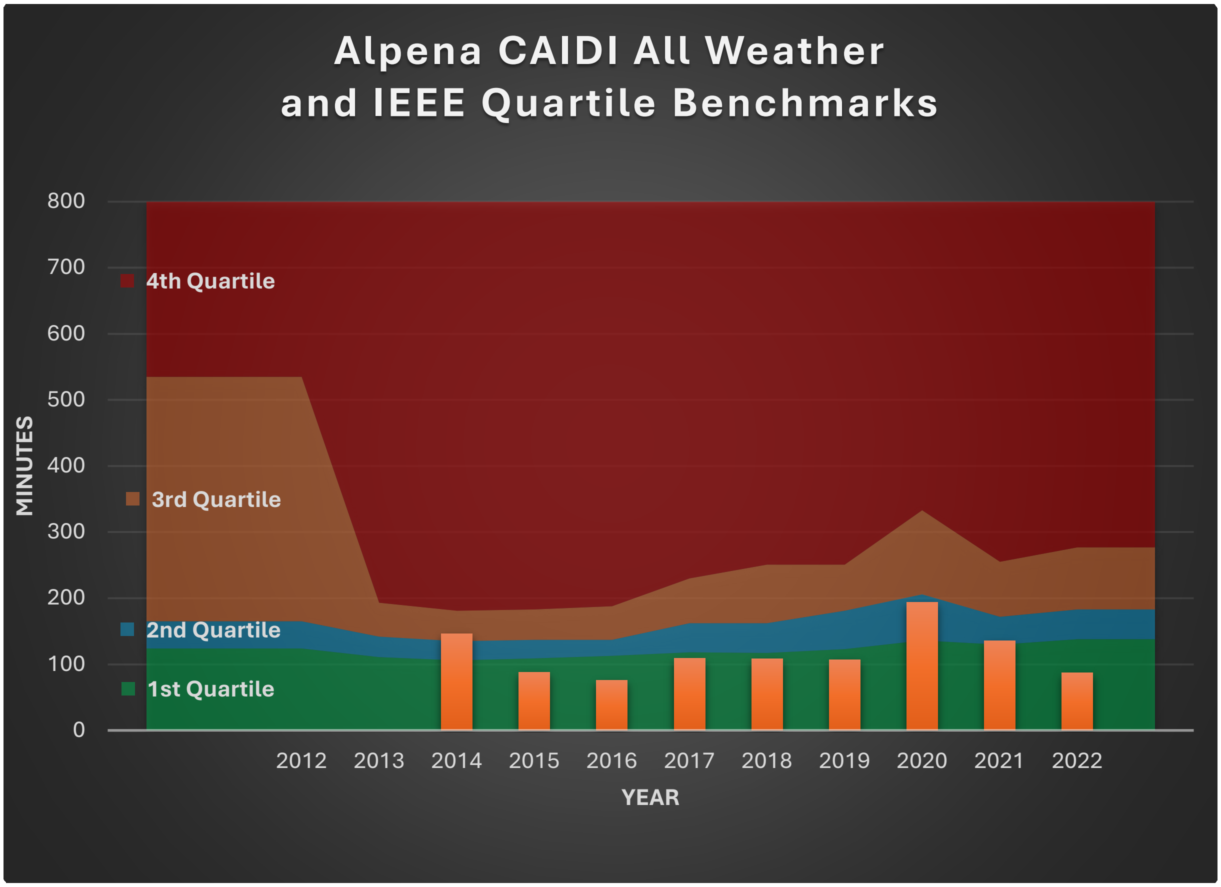

Figure 22: CAIDI All Weather and IEEE Quartile

When compared to the IEEE quartile benchmarks, Alpena's SAIFI is typically in the 2nd or 3rd quartile while SAIDI and CAIDI are in the 1st or 2nd quartile.

3.3.5. Causes of Interruptions

Alpena reviews causes of interruptions in two ways; first is by the number of outage minutes by cause and second is by the number of outage occurrences. Outage minutes drive reliability performance and the impact to our customers while outage occurrence has more of an impact on restoration maintenance costs. Alpena's performance for the last five years is illustrated in the following charts.

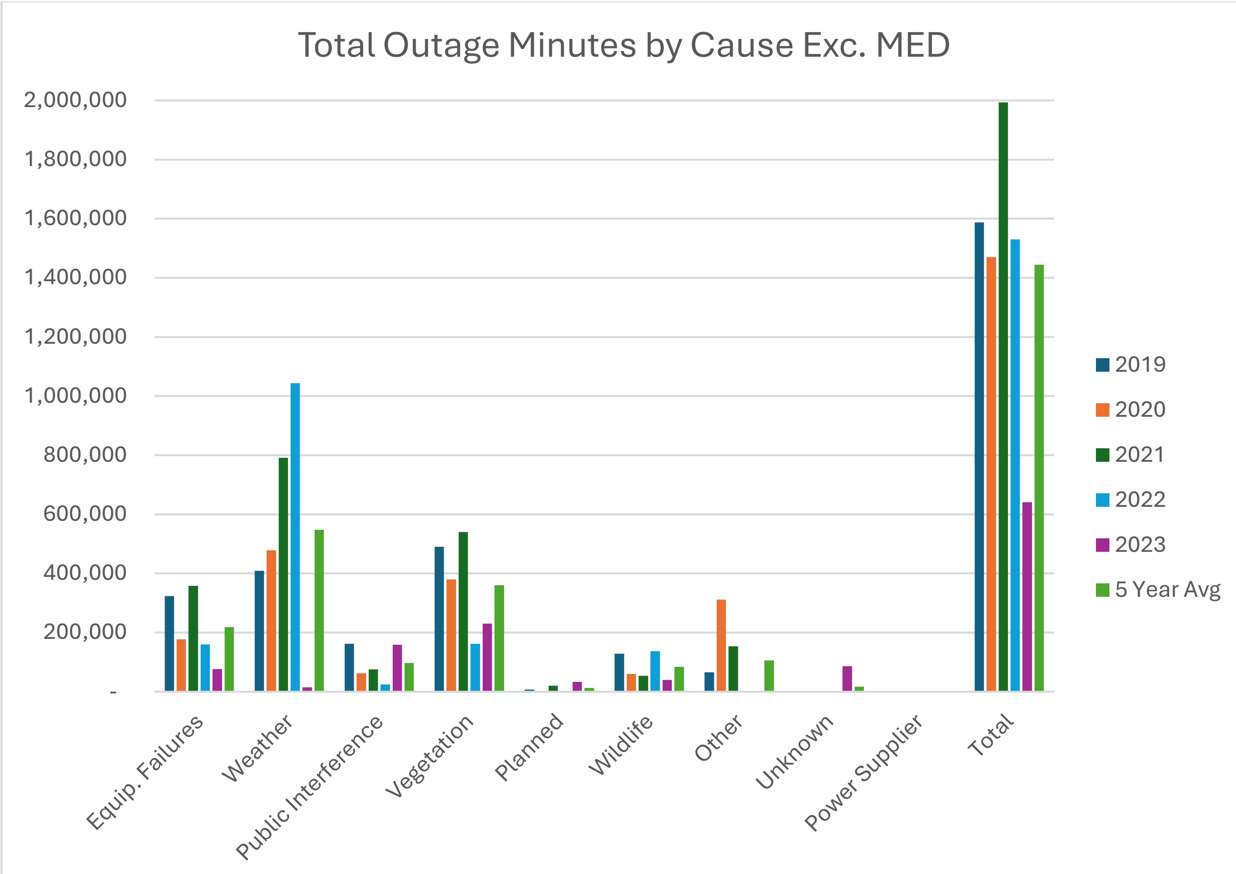

Figure 23: Total Outage Minutes by Cause Excluding MED

Historically, the top two drivers of outage minutes have been weather and vegetation except for 2023 when the outage minutes due to weather dropped significantly. This is due to the previously mentioned change in outage classification from initiating cause to sustaining cause, which reclassifies a large number of minutes from weather to vegetation or equipment failures.

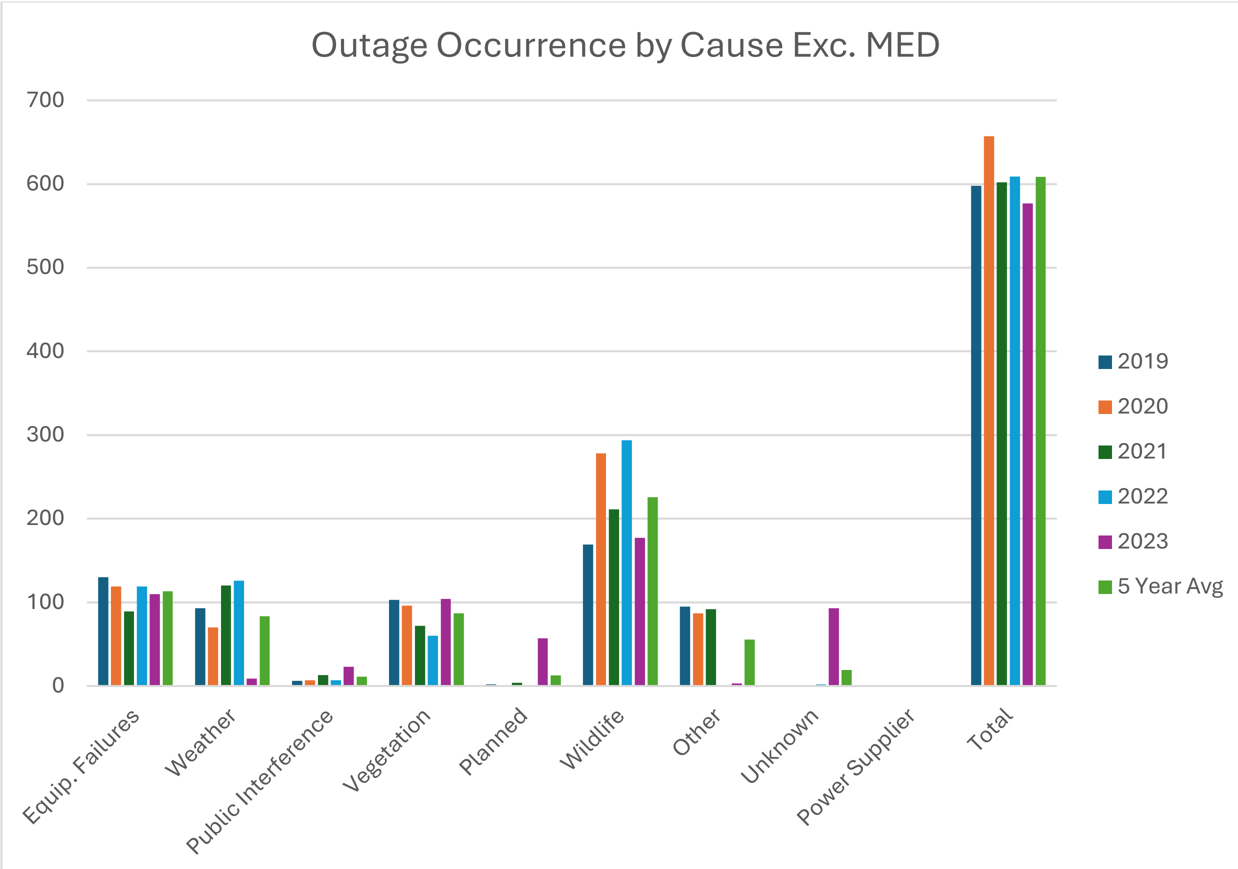

Figure 24: Outage Occurrence by Cause Excluding MED

The leading cause of outage occurrence has been wildlife, and while these outages don't typically lead to a large amount of outage minutes the impact to maintenance costs and wildlife is significant and continuously addressed through the equipment guarding and coverup programs.

3.3.6. Poor Performing Circuits

Alpena's distribution system consists of 40 circuits, five of which are dedicated to a single large customer, and one is a backup with no customers. Those circuits are reviewed on an annual basis to look for reliability trends that can identify issues in small areas of the system. The analysis calculates SAIDI with and without MED on both a circuit basis and system basis. The circuit basis uses the average number of customers on the circuit as the denominator so each circuit, regardless of size, can be compared equally. Whereas system basis uses average number of customers on the entire system to determine which circuits have the largest impact to total system reliability.

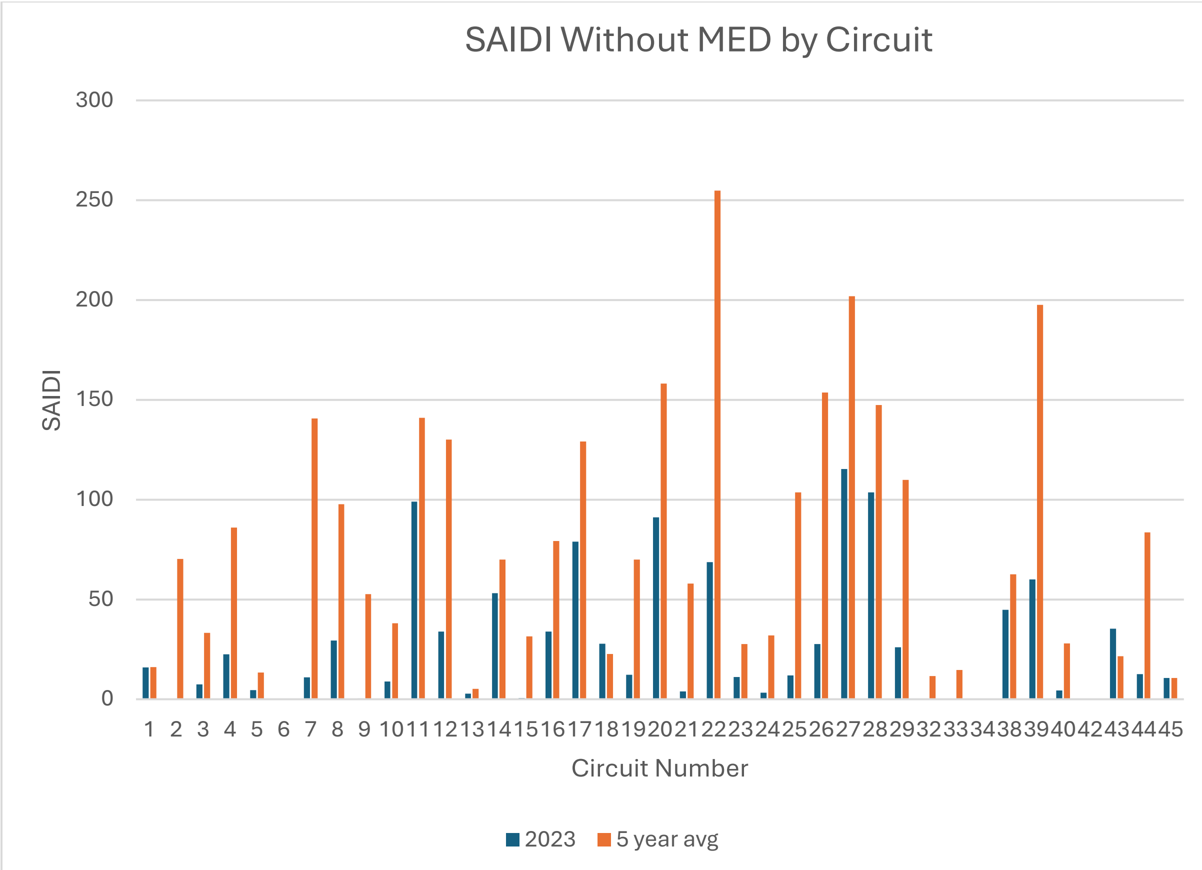

Figure 25: SAIDI without MED by Circuit

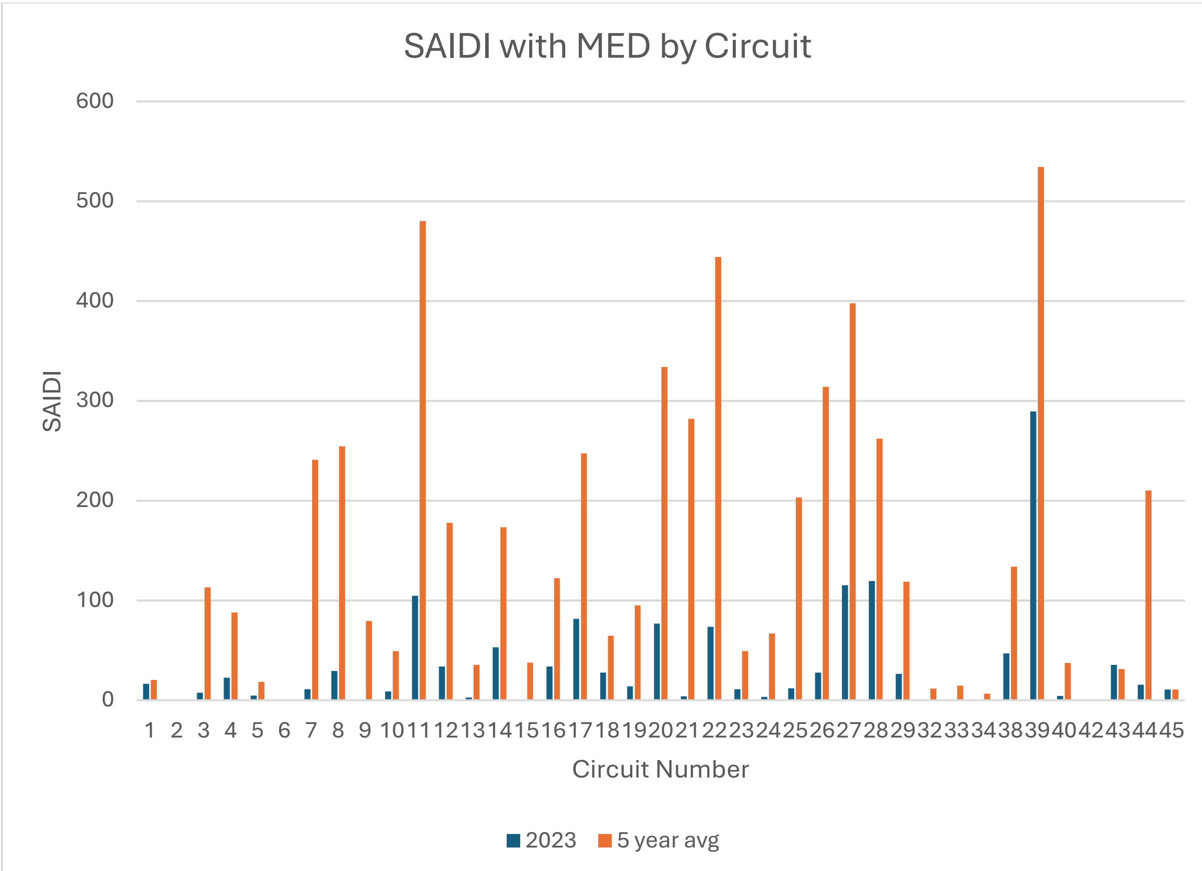

Figure 26: SAIDI with MED by Circuit

On a circuit basis the poorest performing circuits; Circuit 22 Grand Lake, Circuit 39 Spruce Rd, and Circuit 11 Bloom Rd, are rural circuits with large amount of vegetation.

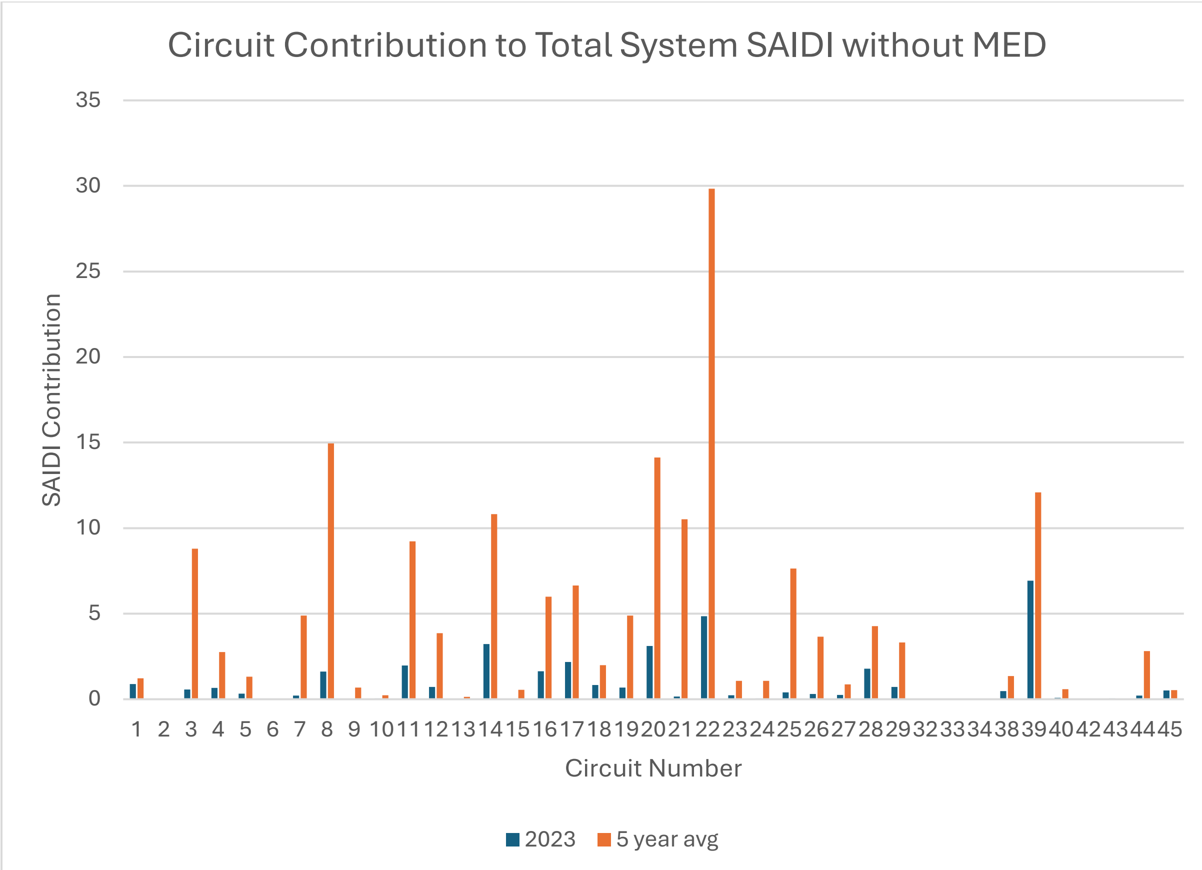

Figure 27: Circuit Contribution to Total System SAIDI without MED

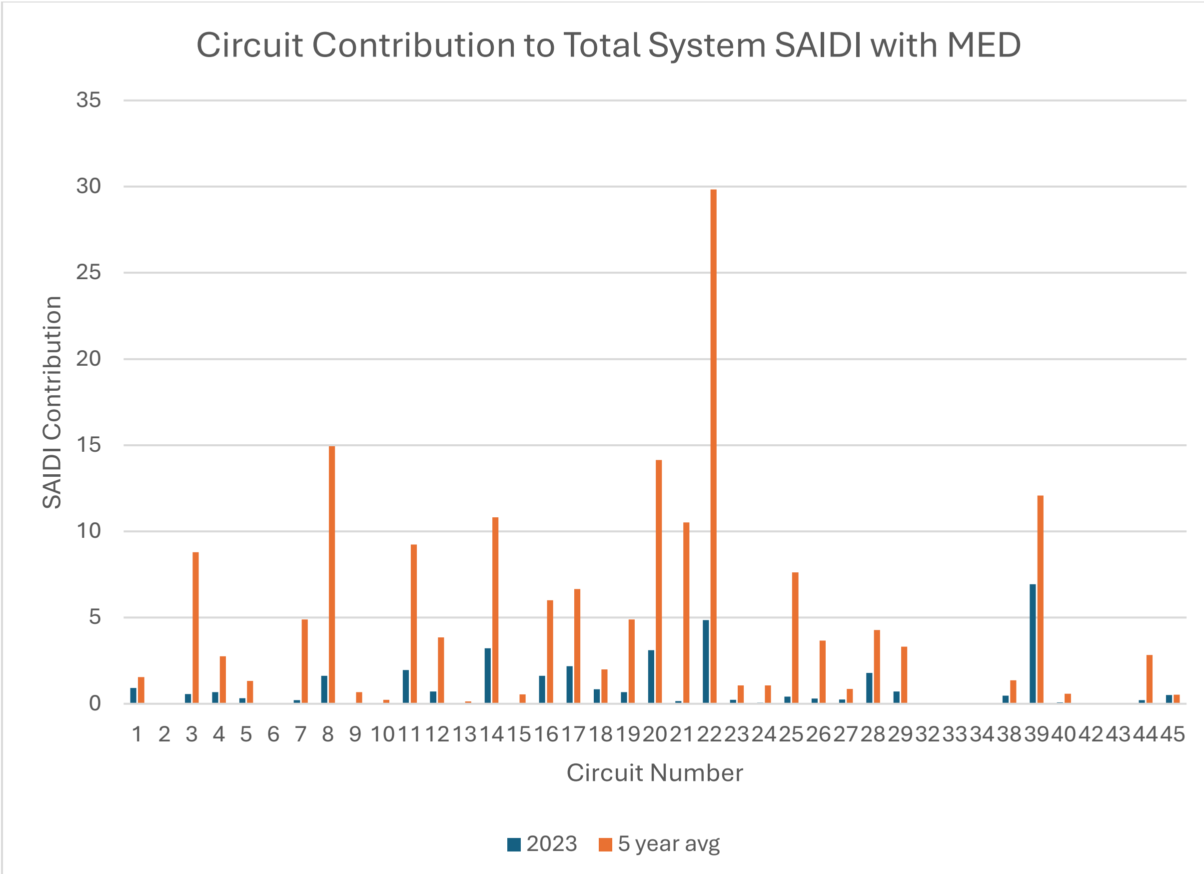

Figure 28: Circuit Contribution to Total System SAIDI with MED

On a system basis the poorest performing circuits; Circuit 22 Grand Lake, Circuit 8 Hubbard Lake South, and Circuit 20 Ossineke, which are some of the largest rural circuits were a smaller number of outages have a large impact on total reliability due to the circuits size.

3.4. Rate Analysis

On a monthly basis the Commission posts to its website a comparison of average rates for Commission-Regulated electric utilities in Michigan[5]. The comparison breaks rates into four customer classes: Residential, Small Commercial, Large Commercial, and Industrial. Each customer class is further broken down by usage and demand. Residential is broken down into three examples by usage: 250 kWh, 500 kWh, and 1,000 kWh. Small Commercial is broken down into two examples by demand and usage, 5 kW / 1,000 kWh, and 25 kW / 5,000 kWh. Large Commercial is broken down into three examples by demand and usage: 100 kW / 21,600 kWh, 100 kW / 28,800 kWh, 100 kW / 36,000 kWh. Industrial is broken

[5] https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/electric/rates1.pdf?rev=2d7916e26a334bcca9fcfa58ce473a44&hash=1E754D89B8CA452DB57A19BBB74ECD93

down into three examples by demand and usage: 1,000 kW / 432,000 kWh, 10,000 kW / 4,320,000 kWh, 50,000 kW / 21,600,000 kWh.

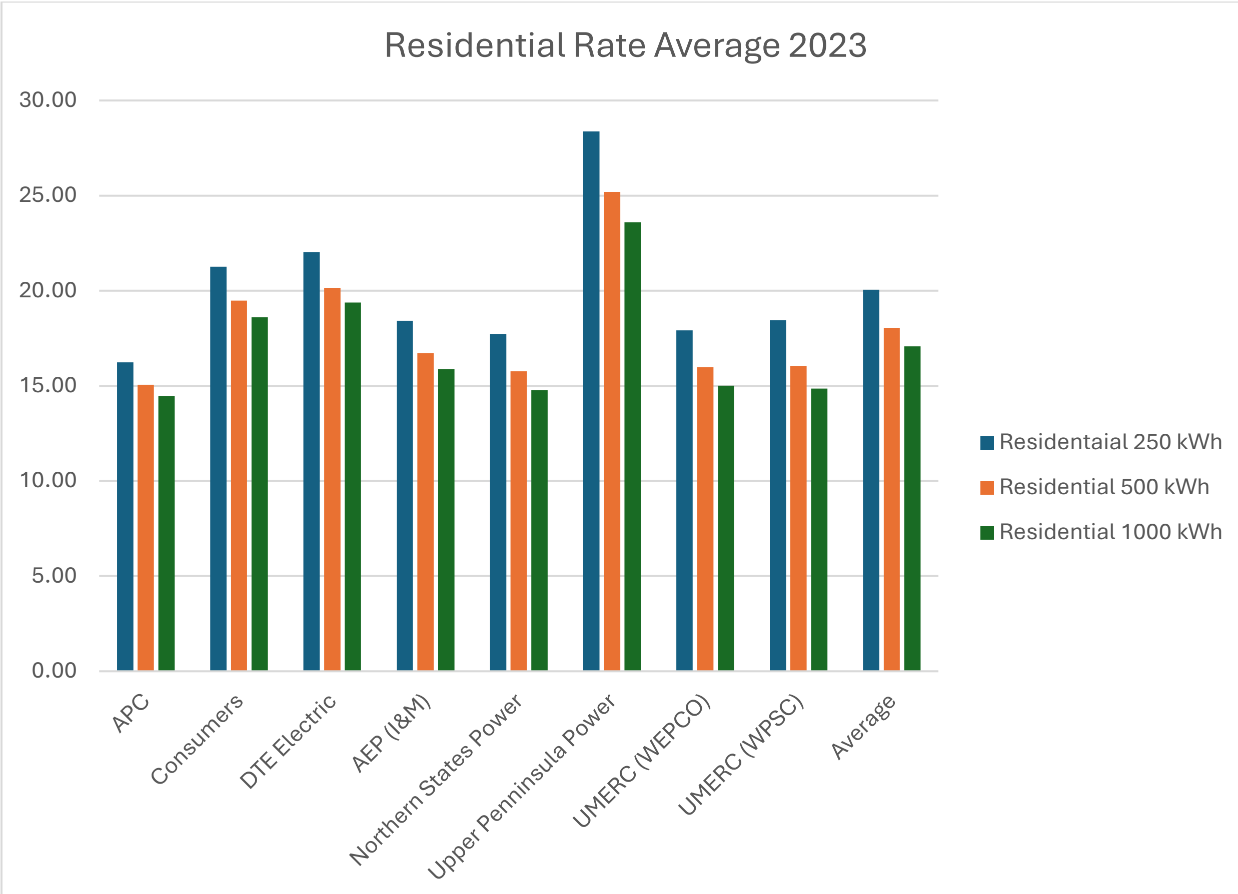

Figure 29: Residential Rates 2023

Alpena’s average residential rates in 2023 were the lowest of the seven IOUs in Michigan and range from 19% to 15% below the average.

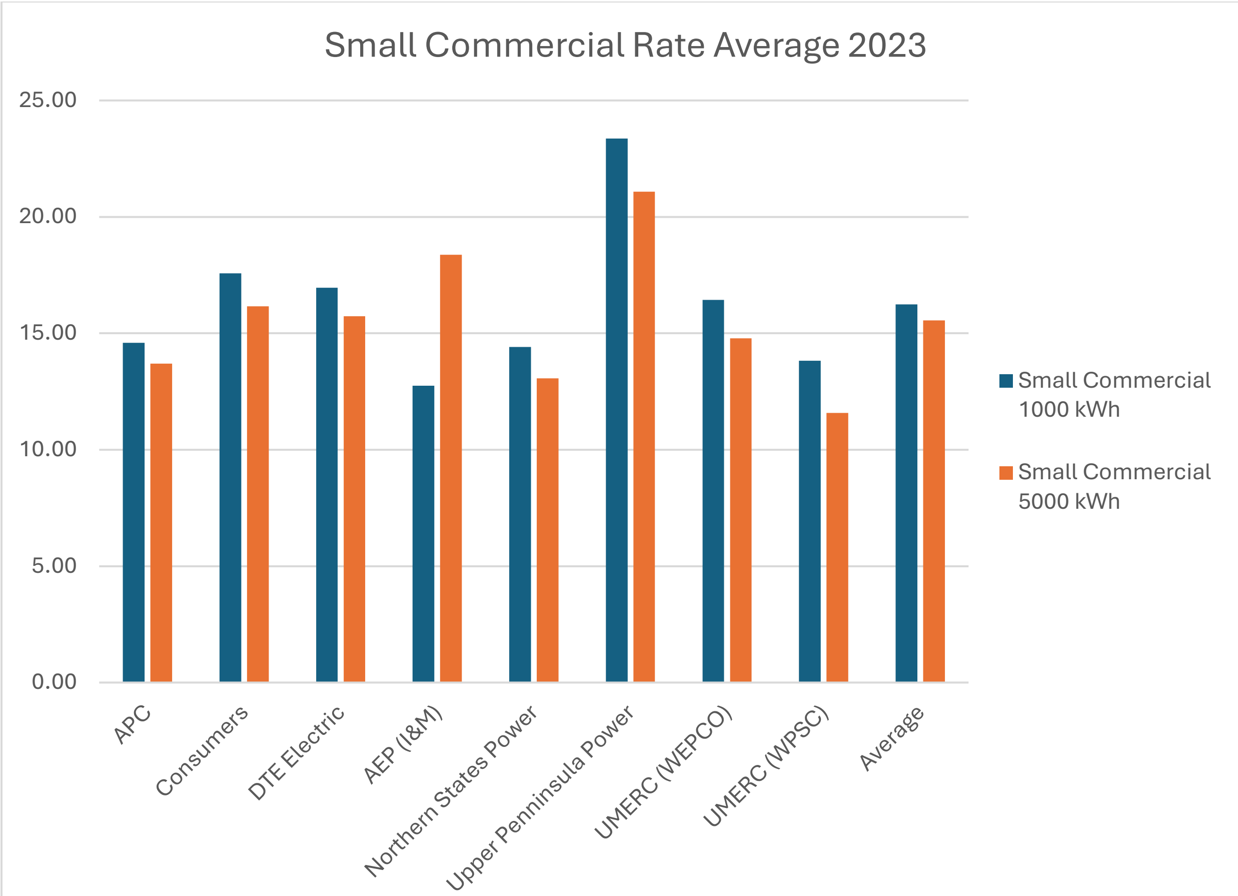

Figure 30: Small Commercial Rates 2023

Alpena's average small commercial rates for 2023 ranked fourth for usage of 1,000 kWh and third for usage of 5,000. When compared to the average Alpena's rates were 10% to 12% below the average rate of the seven utilities.

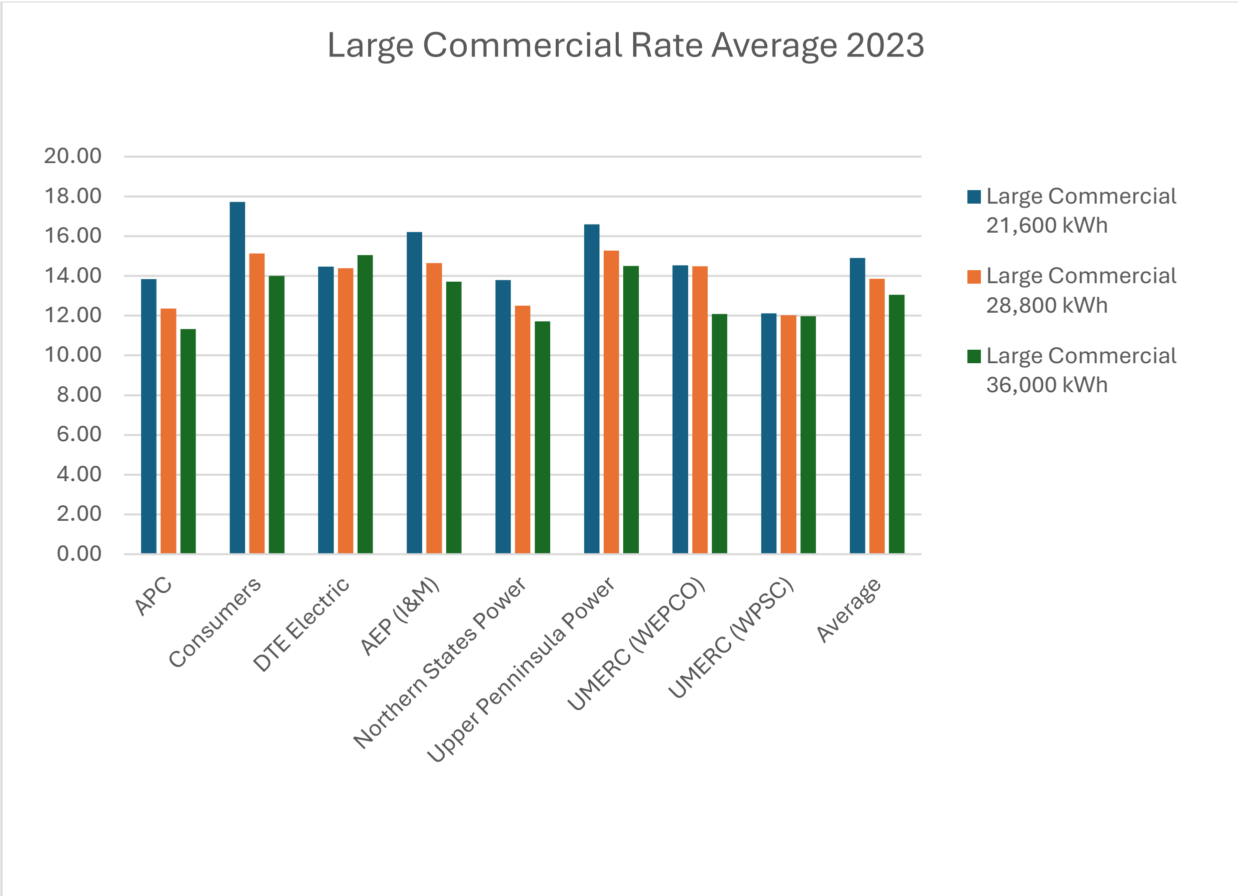

Figure 31: Large Commercial Rates 2023

Alpena's average large commercial rates for 2023 ranked third for usage of 21,600 kWh, second for usage of 28,800 kWh, and lowest for usage of 36,000. When compared to the average Alpena's rates were 7% to 13% below the average rate of the seven utilities.

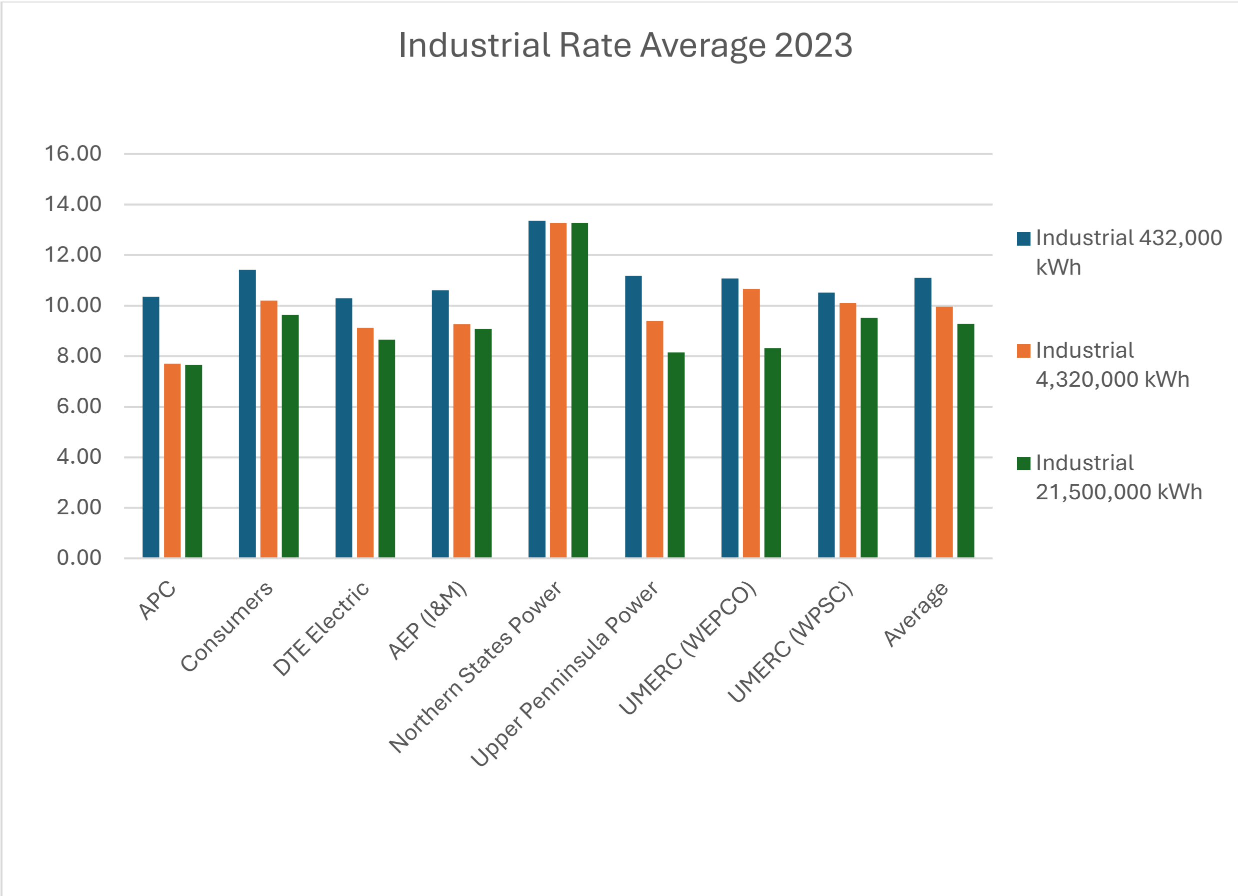

Figure 32: Industrial Rates 2023

Alpena's average industrial rates for 2023 ranked second for usage of 432,000 kWh, and lowest for usage of 4,320,000 and 21,500,000 kWh. When compared to the average Alpena's rates were 7% to 23% below the average rate of the seven utilities.

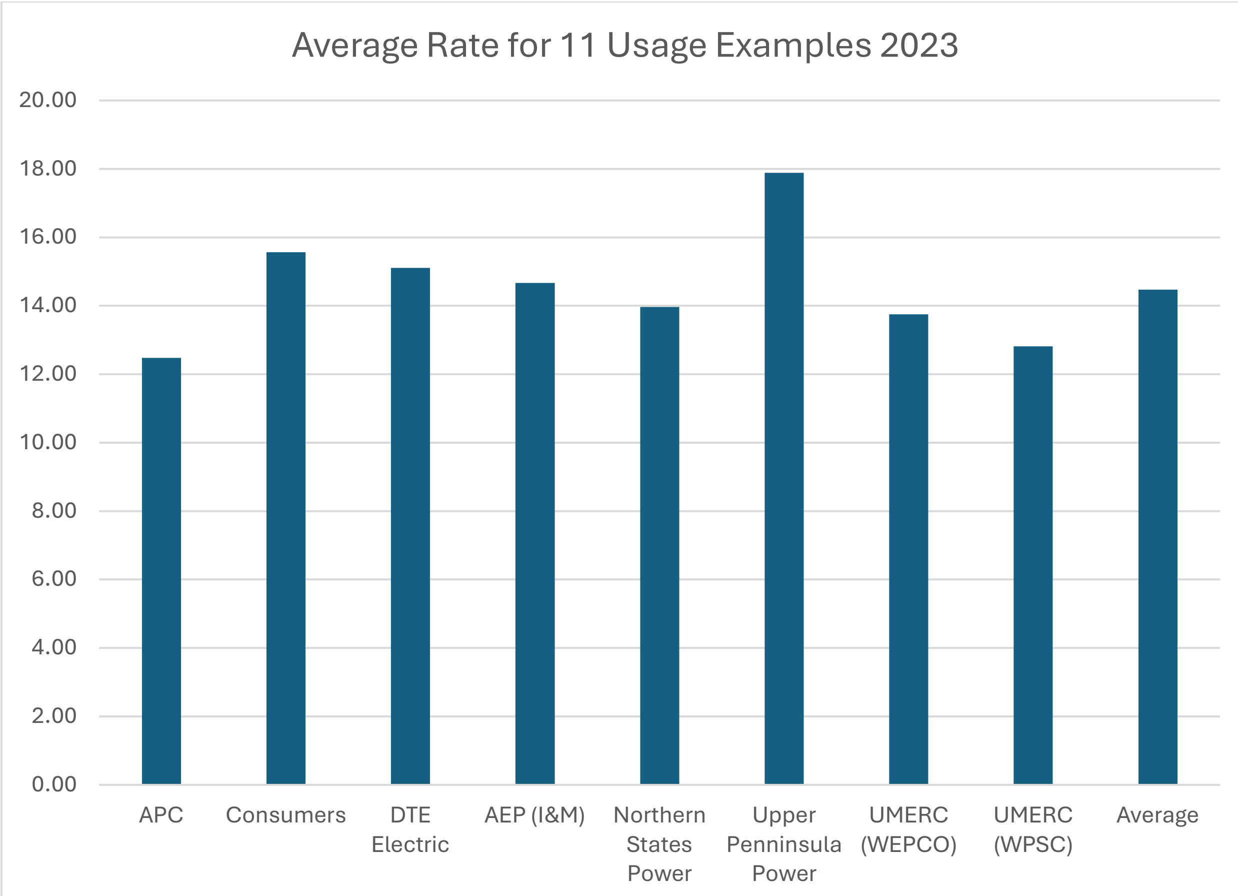

Figure 33: Overall Average Rates 2023

To compare an overall rate for utilities Alpena averaged the eleven usage examples posted on the Commission's website and was the lowest of the seven IOU's and 14% below the average.

4. Future Drivers of Change

As part of the planning process, Alpena analyzes the potential grid impacts caused by EV adoption, changes to weather patterns and increasing extreme weather events, and increasing penetration of Distributed Generation (DG). This section describes how each driver affects Alpena's distribution system and load forecast.

4.1. Electrification

Electrification in general terms, is the conversion of fossil fuel-based energy sources, to an electric energy source, such as for transportation, home heating, and home appliances. While all types of electrification will have an impact on Alpena's distribution system, transportation electrification was the primary driver analyzed.

Alpena includes in the long-term forecast the number, consumption, and demand for EV's by customer classes.

The forecast for the number of EVs in Alpena is based on the national EV penetration rate forecasted by the Energy Information Administration (EIA) as part of their Annual Energy Outlook in 2023. The process can be summarized in four steps. First, the US EV penetration rate is calculated from EIA data for 2022 and each forecast year provided. Second, the historical EV penetration rate in Alpena County is calculated for 2022 as the total number of EVs divided by the total number of vehicles. The number of EVs in Alpena's territory is provided by the State of Michigan Community EV Toolkit. The total number of Alpena County vehicles is calculated using a survey of the number of vehicles per household (provided by American Community Survey) multiplied by the number of households in each year. Third, the forecasted Alpena EV penetration rate is assumed to maintain the same relative difference to the national forecast as was calculated in 2022. For example, the US and Alpena EV penetration rates were 1.15% and 0.10% in 2022, respectively. The EIA forecast assumes that the US EV penetration rate will increase by 0.35 percentage points in 2023 (from 1.15% to 1.50%); therefore, the Alpena EV penetration rate is also assumed to increase by 0.35% percentage points in 2023. Fourth, and finally, the total number of forecasted EVs for Alpena is calculated as the product of the EV penetration rate forecast and the total number of vehicles forecast.

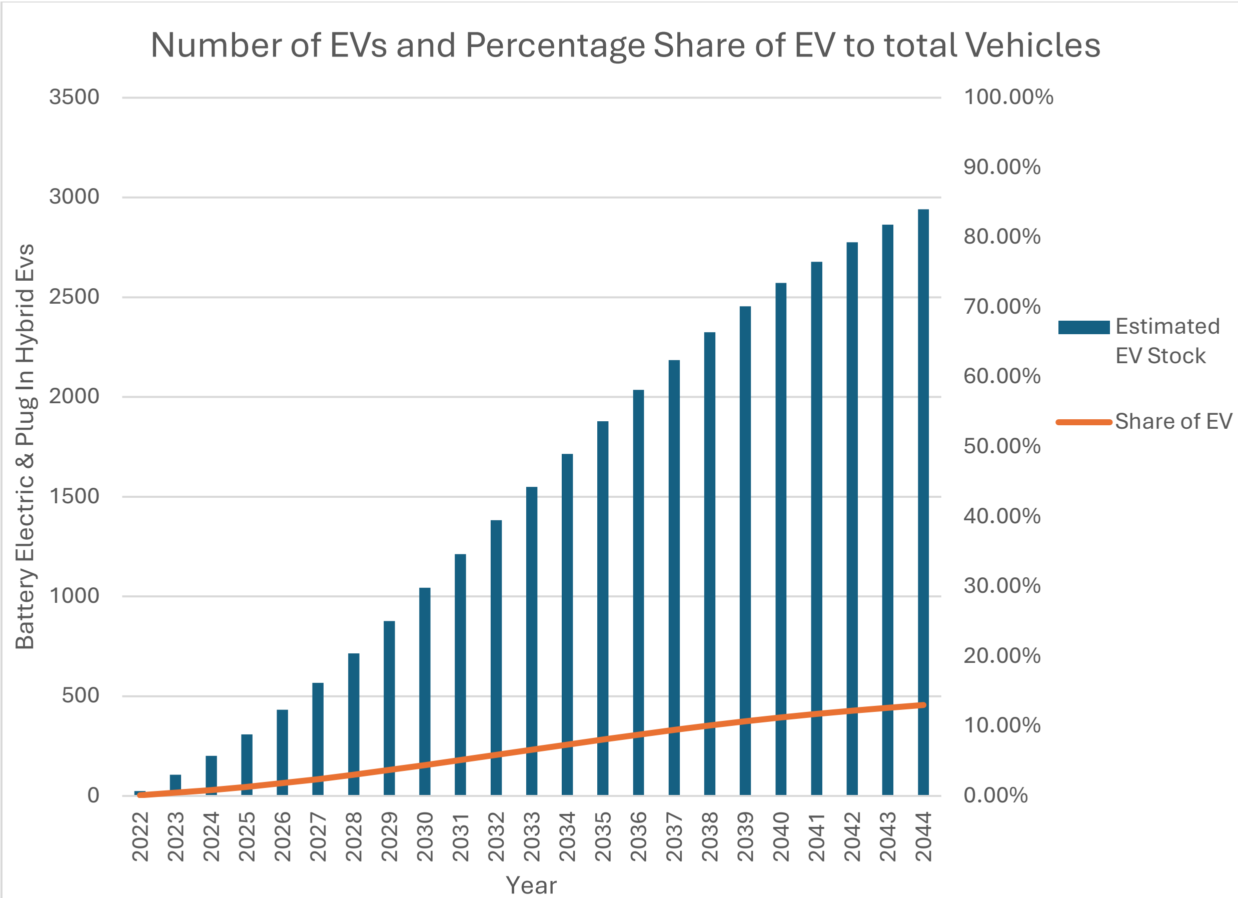

Figure 34: Number and Percentage Share of EVs

The forecasted energy and demand values for EVs is determined using the Electric Vehicle Infrastructure Projection Tool (EVI-Pro), provided by the US Department of Energy, to simulate EV load profiles. Hourly weekday and weekend load profiles that are differentiated by home versus public charging and the level of charge (level 1, 2, DCFC). Monthly energy and demand estimates per EV are then calculated from these load profiles using appropriate weights for the number of weekdays versus weekends by month.

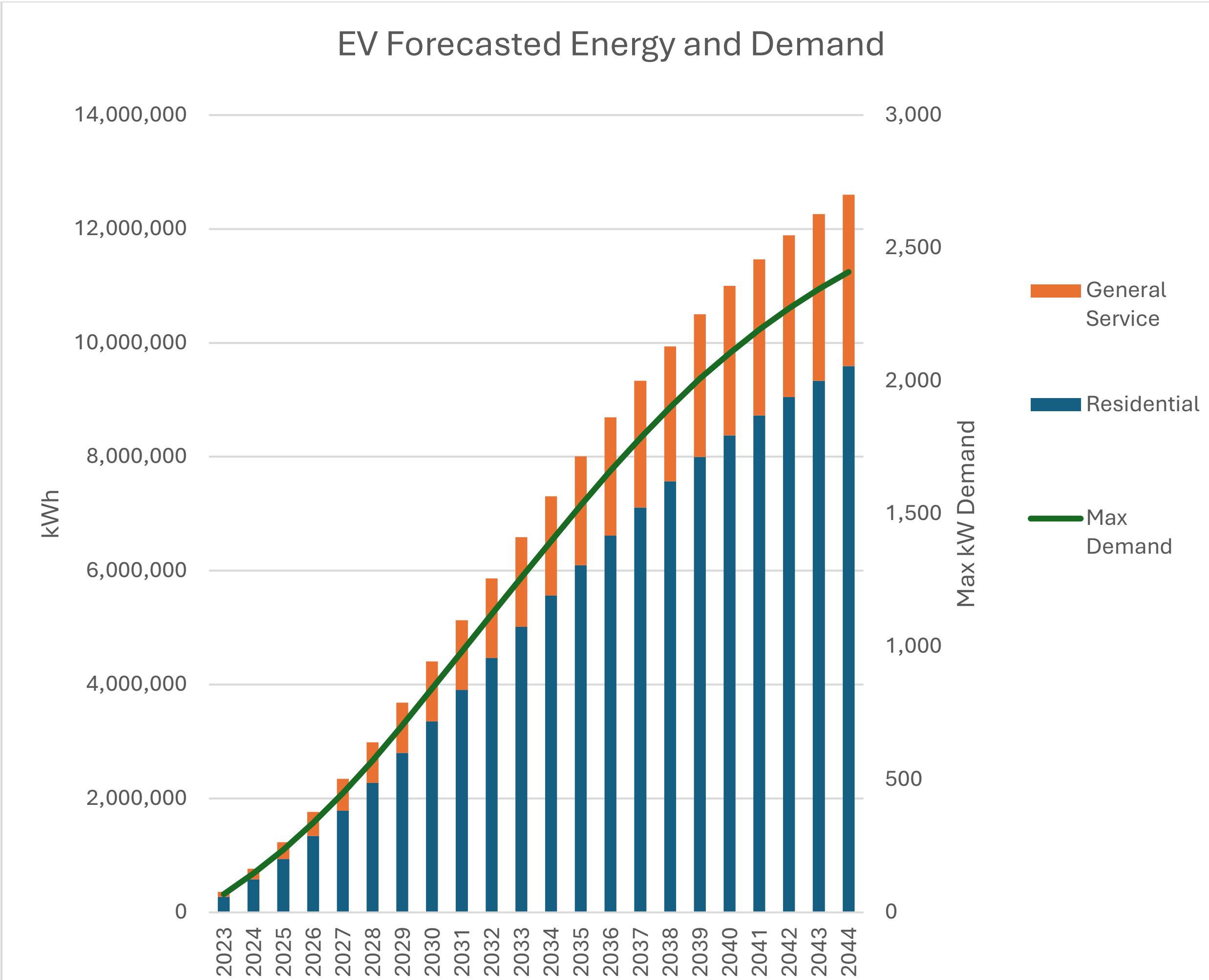

Figure 35: EV Forecasted Energy and Demand

4.2. Weather

Alpena's service territory in northeastern lower Michigan has been experiencing changes in weather patterns and climate, similar to utilities across the country, and felt their impact on operations. Over the past 15 years Alpena has seen an increase in the number of major storm events, defined as an outage to more than 10% of the customer base.

The following are a description of the major storms from the past 5 years.

- 2019
  - No major storm events.
- 2020
  - On April 13, a major windstorm impacted Alpena County. The storm lasted two days and resulted in 1,931 customers losing power for a total of 456,510 minutes. South Shore circuit and Werth Rd. circuit out of South Sub, M-32

West circuit out of M-32 substation, and King Settlement circuit out of Southwest substation all went out during the storm.
    - On December 12, parts of Alpena's service territory were hit with a major winter storm. Certain areas saw 12-16 inches of wet, heavy snow, as well as very high winds. The damage left 1,663 customers without power for a total of 1,593,700 minutes. All customers were restored by the night of the 15th, making this storm the worst Alpena experienced in decades.
- 2021
    - On April 30, a major windstorm impacted Alpena County. The storm caused a tree to fall and land on a 34.5 kV subtransmission line, resulting in the loss of power to M-32, Ontario, South, and Ossineke substations. A total of twelve circuits are fed from those substations. A tree also landed on the three-phase line out of Rockport sub resulting in the loss of power to the entire Grand Lake circuit. A total of 5,967 customers lost power during the storm for a total of 639,735 minutes.
    - On August 29, parts of Alpena's service territory were hit with a major thunderstorm. The wind accompanying the thunderstorm caused extensive tree related damage to the system. Squaw Bay circuit out of Ossineke substation was lost for a period of time due to multiple trees on the three-phase line. In total, 1,941 customers lost power for a total of 872,678 minutes.
    - On December 16, Alpena County was hit by a significant windstorm that resulted in several tree related outages. Werth Rd. circuit out of South substation, East Long Lake circuit out of Northeast substation, and Grand Lake circuit out of Rockport substation were all out due to trees on the three-phase lines. In total, 2,906 customers lost power for a total of 537,009 minutes.
- 2022
    - Starting on June 16, a major windstorm impacted Alpena County. The storm caused widespread tree damage, resulting in many downed lines and widespread outages. At various times during the storm Alpena lost Hubbard Lake North, Hubbard Lake South, Grand Lake, King Settlement, Hillman, East Long Lake, and Long Rapids Rd West circuits. A total of 5,434 customers lost power during the storm for a total of 587,165 minutes.
    - On August 5, a thunderstorm event caused an outage at Potter Field subtransmission substation. The resulting outage effected Hubbard Lake, M-32, Ontario, Ossineke, Southwest, and South substations. In total 6,139 customers lost power for a total of 196,378 outage minutes.
    - On November 3, a weather event caused a fault on the regional transmission system resulting in an operation of Alpena's Four Mile substation #588, 138

kV breaker. The ensuing outage effected Gennrich, Lafarge, Central, Rockport, Northside, and Northeast substations. In total 6,002 customers lost power for a total of 337,730 minutes.

- 2023
  - No major storm events.

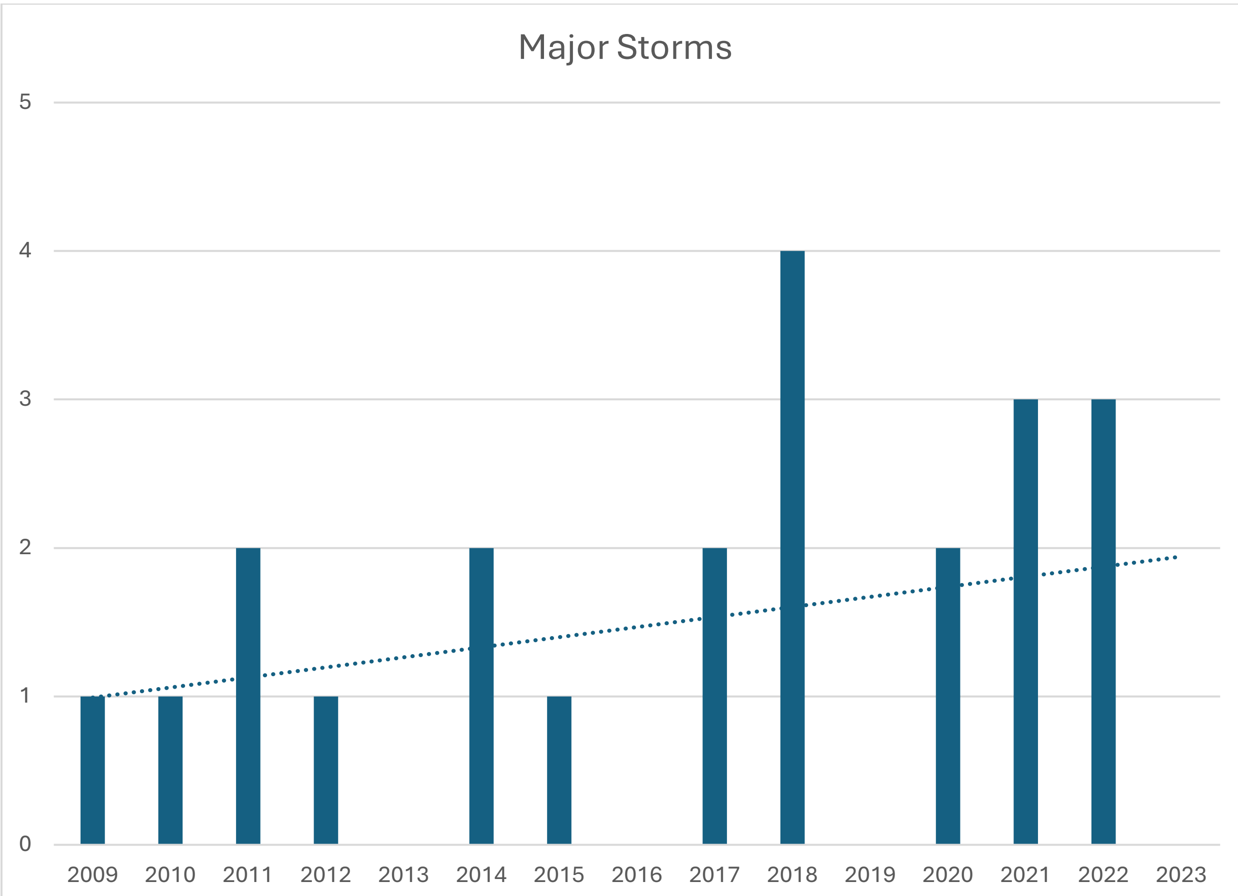

Figure 36: Number of Major Storms

Major storms can come in many forms, wind, snow, ice, thunderstorms, or a combination of types. In many storms wind plays a significant factor, specifically wind gusts, and appears to be increasing due to the effects of climate change. When measured at the Alpena County Regional Airport[6] average wind speed has remained flat but the number of days with wind gusts over 35, 40, and 45 miles per hour (MPH) as increased significantly since 2004.

[6] National Oceanic and Atmospheric Administration Weather Station Alpena County Regional Airport (KAPN)

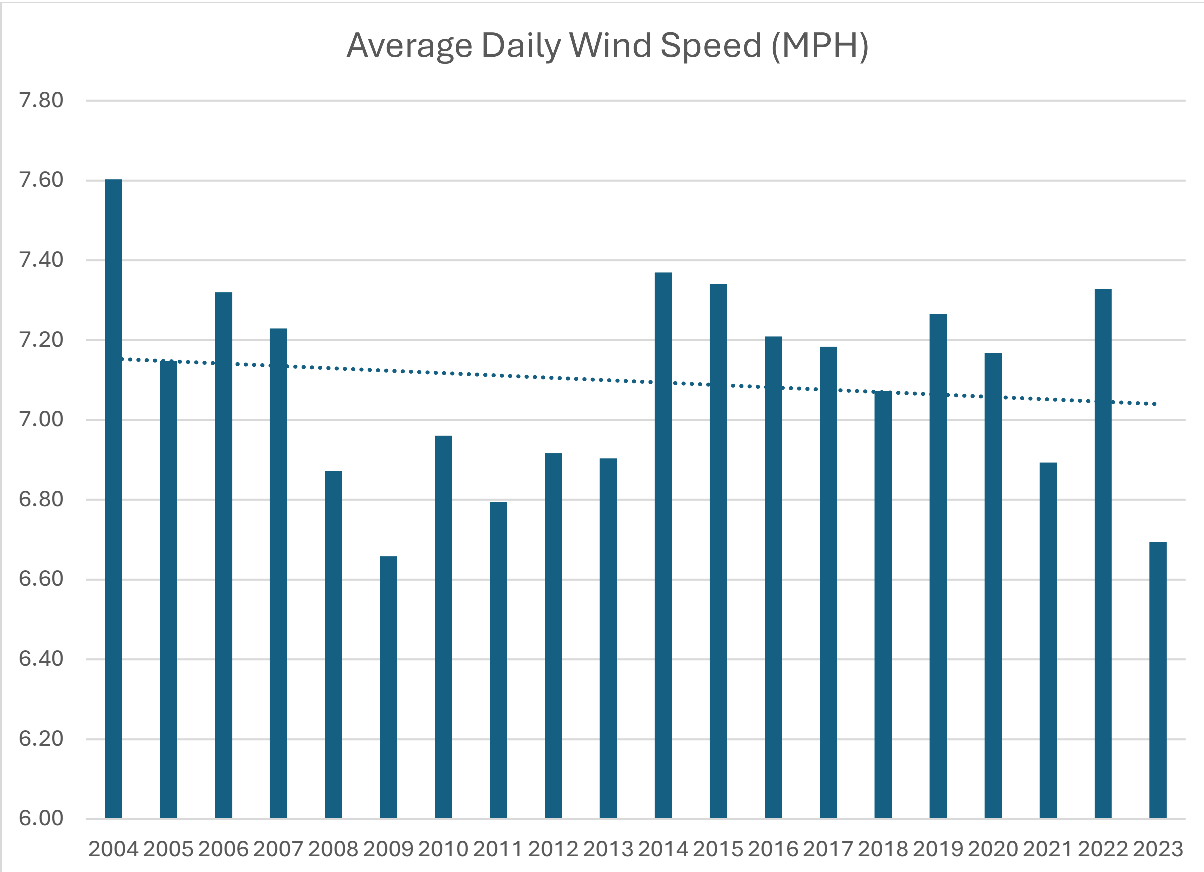

Figure 37: Average Daily Wind Speed at Alpena County Regional Airport

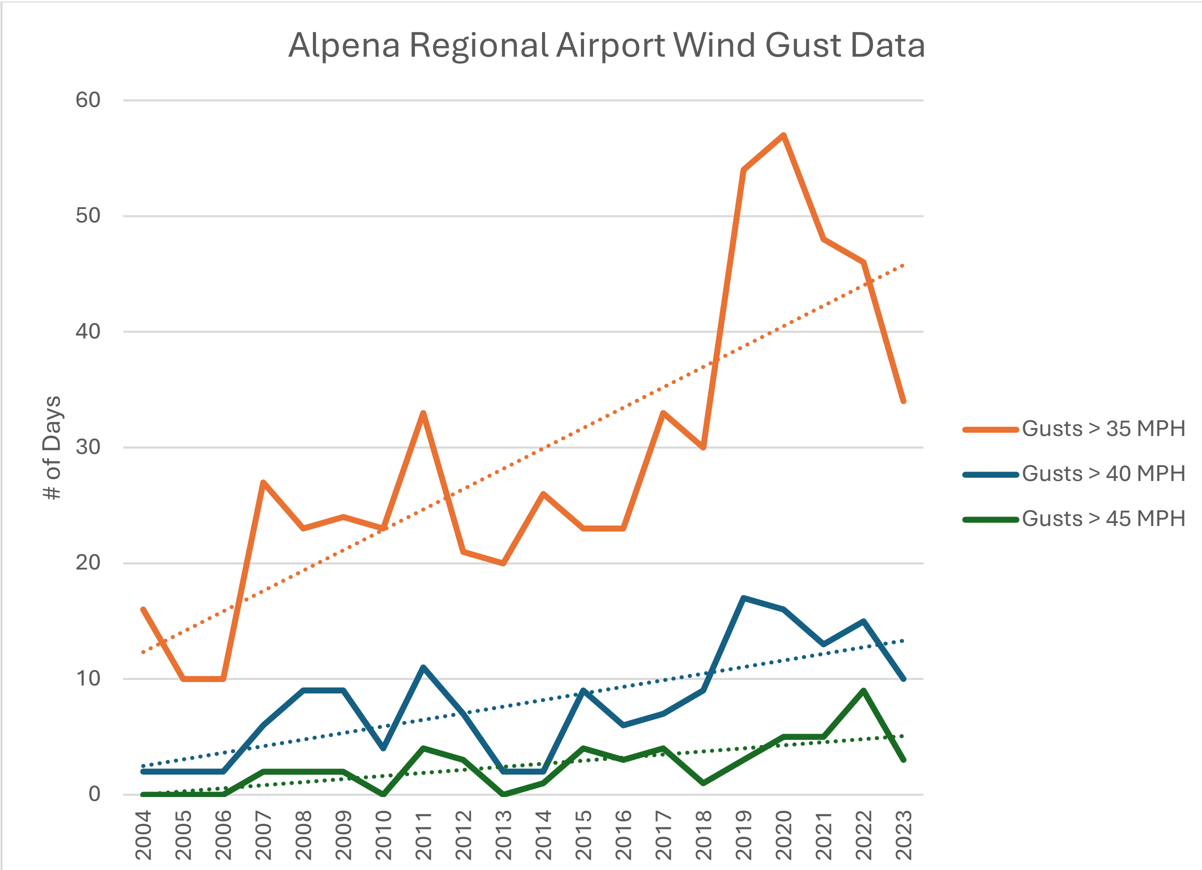

Figure 38: Wind Gust Data at Alpena County Regional Airport

It is the experience of the Company that wind gusts over 40 MPH have a significant impact on vegetation and typically lead to increases in tree related outages.

Winter storms can have a significant impact on the distribution system, especially when they include wet snow or ice buildup. Norther MI is accustomed to winter storms with significant amounts of snow, but the impact of the snow usually depends on its density. Snow accumulation with colder temperatures is light and a foot of snow when it is 15 °F usually has little effect on the distribution system. However, if the same snow accumulation is during warmer temperatures close to 30 °F the snow becomes sticky, heavy, and leads to tree damage.

Temperatures over the past 20 years have been increasing in the Alpena area and when accompanied by snowfall can lead to a large number of outages.

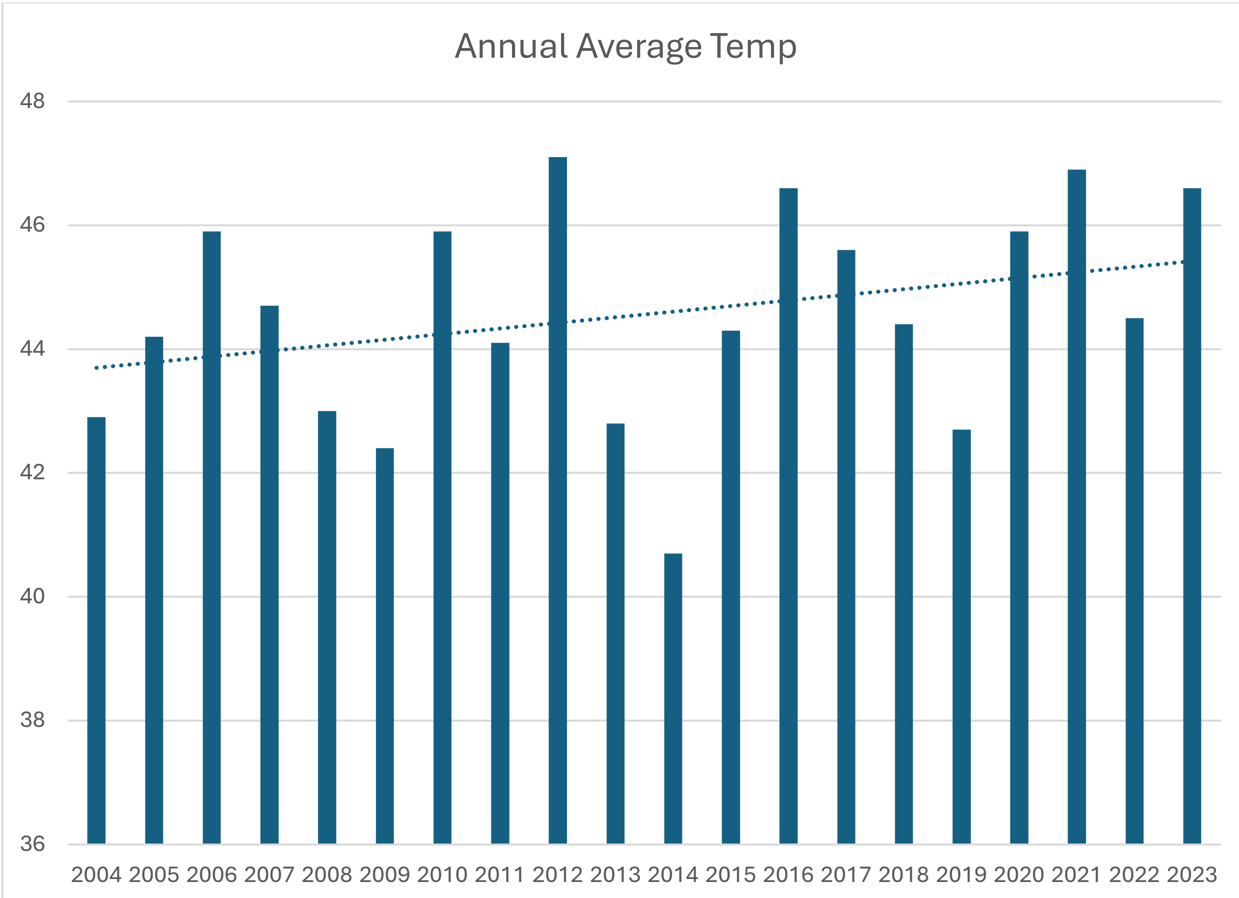

Figure 39: Annual Average Temperature at Alpena County Regional Airport

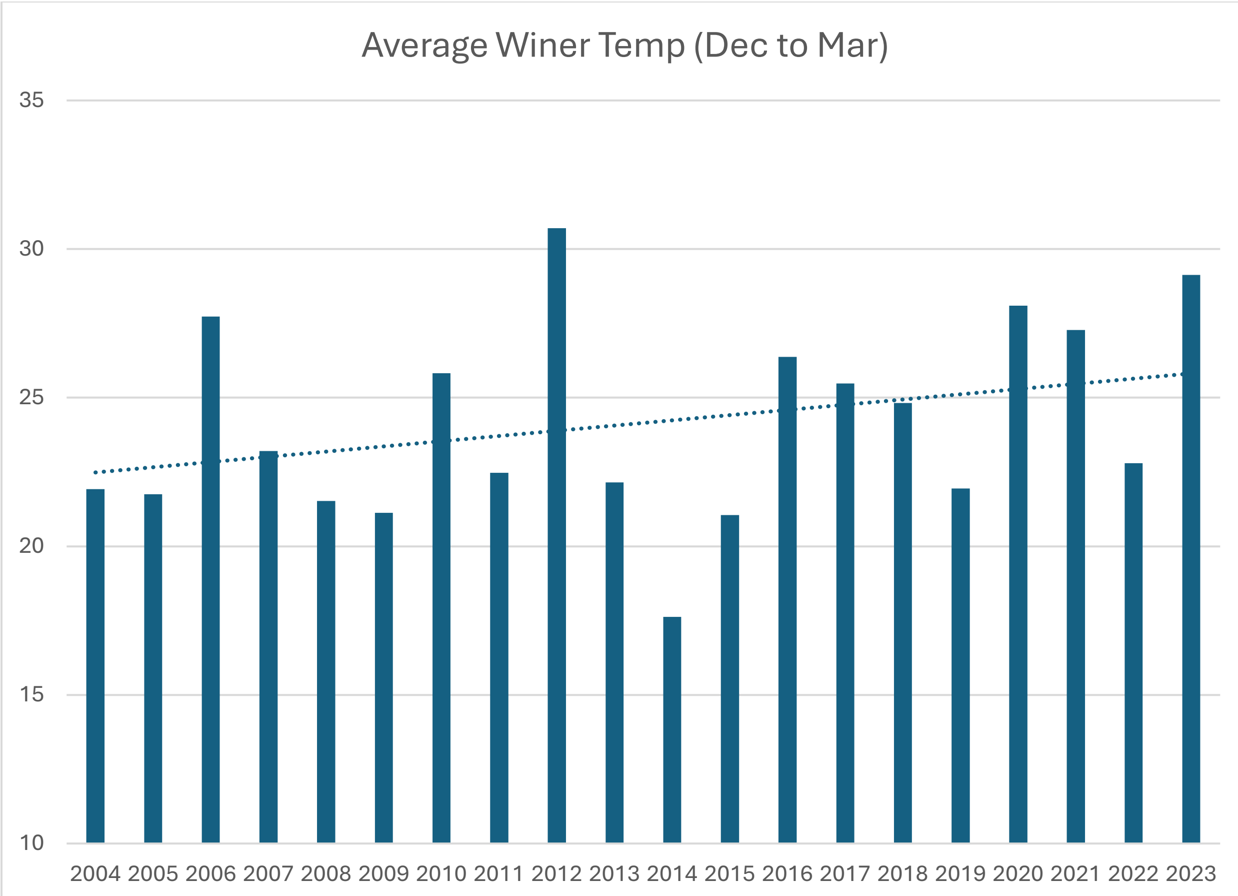

Figure 40: Average Winter Temperature at Alpena County Regional Airport

Thunderstorms can also be a significant contributor to outages due to high winds, lightning strikes, and heavy rains. An indicator of thunderstorm potential is the number of days with higher Convective Available Potential Energy (CAPE), which according to the National Weather Service, is the amount of fuel available to a developing thunderstorm[7]. Higher CAPE days have become more common in Michigan, with the highest increases in the northern lower and eastern upper peninsula[8].

[7] https://forecast.weather.gov/glossary.php?word=Cape
[8] https://www.climatecentral.org/climate-matters/changing-thunderstorm-potential

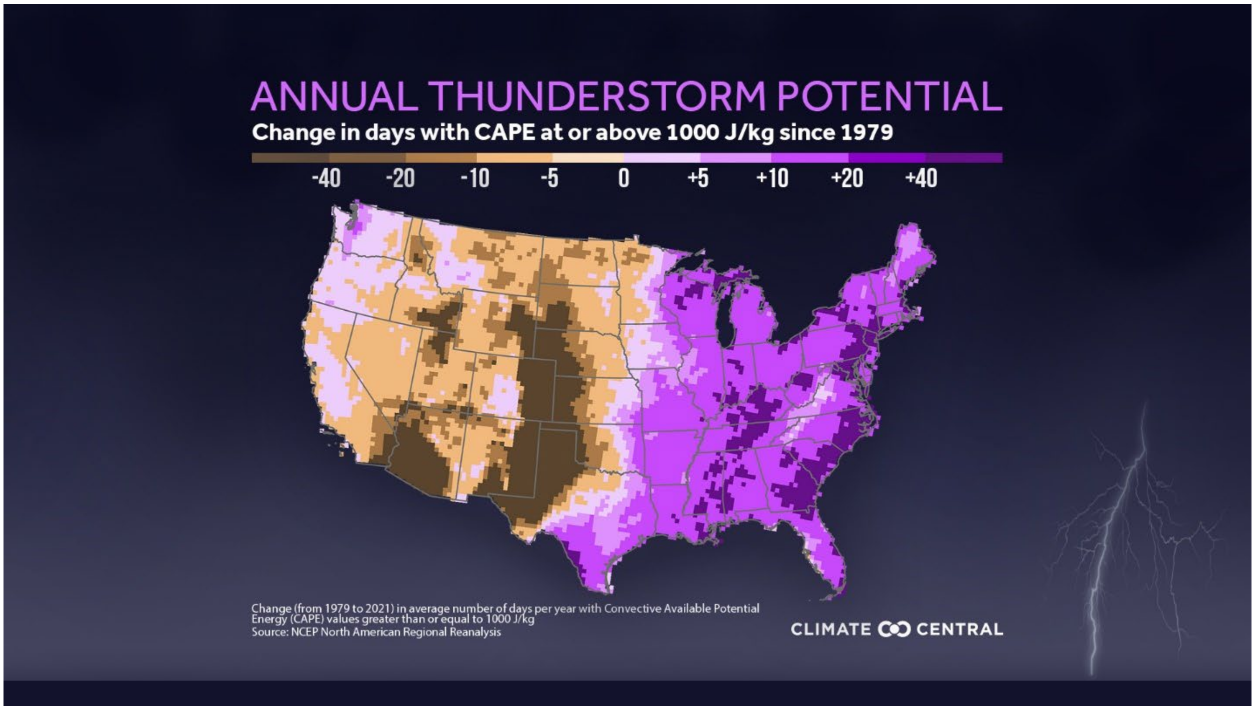

Figure 41: Annual Thunderstorm Potential

4.3. Distributed Generation / Distributed Storage

Distributed Generation (DG) and Distributed Storage (DS) is a subset of Distributed Energy Resource (DER) technologies defined by the MPSC[9] as, "source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage technologies capable of exporting active power to a distribution system."

As of January 1, 2024, Alpena has 27 customers enrolled in its DG and Legacy Net Metering program with a combined capacity of 150.8 kW, which is approximately 0.25% of peak load and a low penetration rate when compared to other utilities in the state. Of the installed capacity 112.6 kW is solar while 38.2 kW is wind. Alpena has no known DS installed as of January 1, 2024.

To forecast future DG growth Alpena reviewed DG capacity additions since 2016 as that was the first occurrence of residential solar on APC's system and it is assumed that new DG capacity additions will also be solar. Therefore, DG capacity is assumed to increase by 11.7 kW each year.

[9] MPSC Case U-20147, August 20th Order, Page 11.

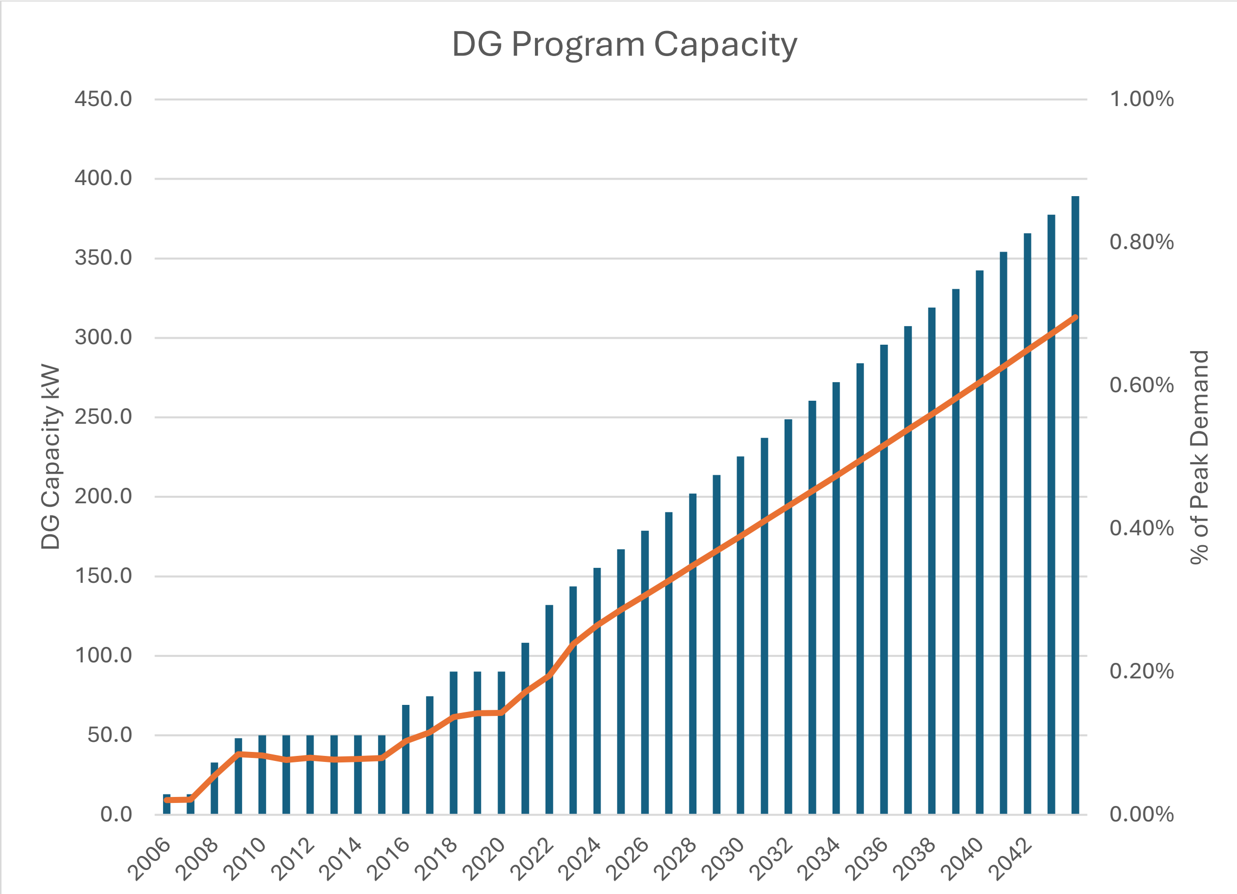

Figure 42: Distributed Generation Program Capacity

To determine the DG program additions to the load forecast the profile of solar output for residential DG is simulated using publicly available System Advisor Model (SAM) software provided by the National Renewable Energy Laboratory (NREL). The simulation produces an hourly solar load profile specific to Alpena County for an entire year assuming a nameplate capacity of 2.9 kW. Solar output is aggregated monthly and converted to a per-kW basis of nameplate capacity. The energy-related impact is the total solar output while the demand-related impact is solar output coincident with APC's monthly system peak.

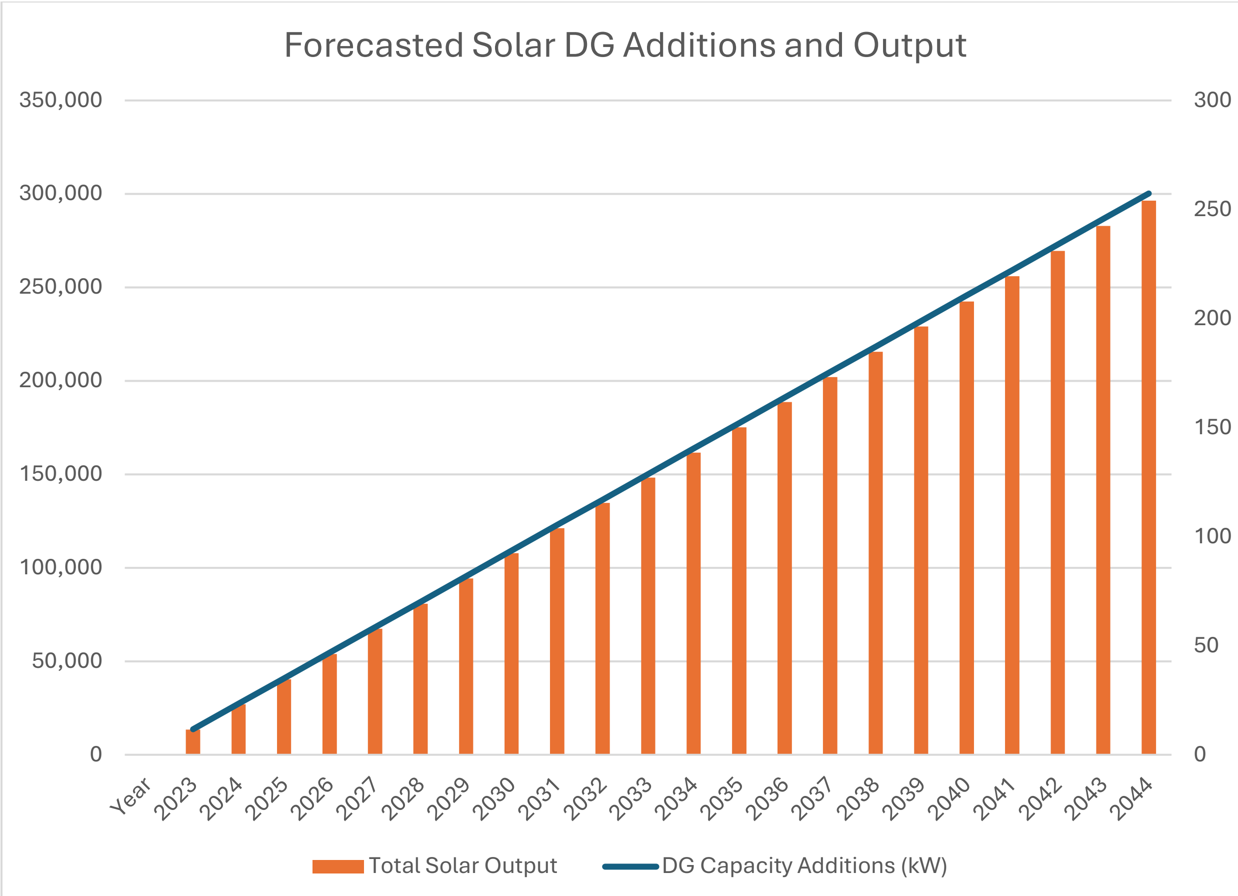

Figure 43: Forecasted DG Additions

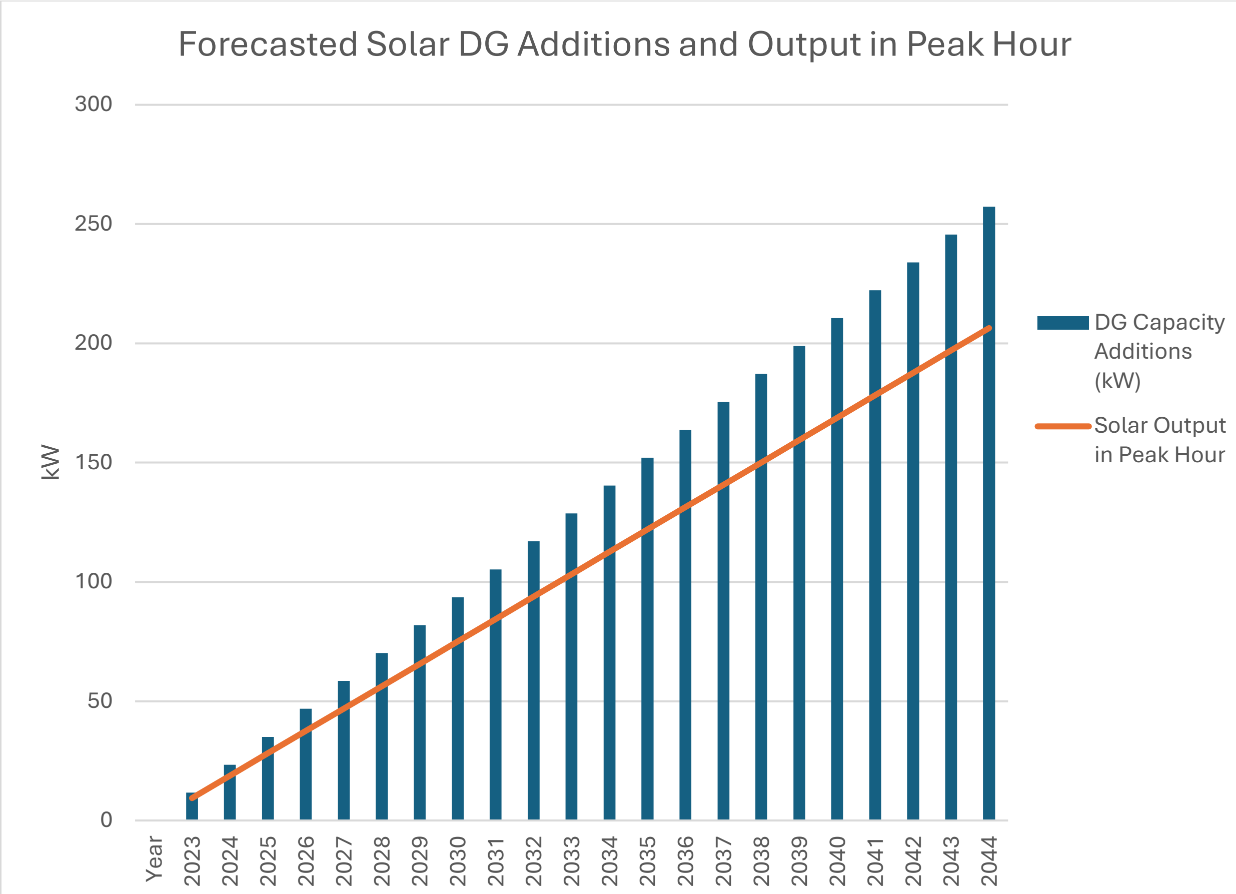

Figure 44: Forecasted DG Additions and Peak Output

To apply the DG forecast to the energy and demand forecasts the forecasted increase of DG is calculated as the product of increased annual DG capacity and the solar output per capacity. Separate forecasts are provided for energy and demand amounts. The Residential customer class has their energy and demand forecasts reduced by the amount of the DG forecasts.

4.4. Load Forecast

The long-term energy forecast for most customer classes is developed from separate models of the number of customers and use per customer (UPC). This is done for Residential, General Service, Standard Power, Large Power, Protective Lights, and Street & Highway Lights. Customer-specific UPC forecasts are developed for the Large Industrial and Special Power Contract customers. The product of the number of customers and UPC forecasts gives the forecast for total energy. A regression specification is formulated for each model and is estimated using historical data going back to 2004. The regression specifications model the number of customers and UPC as a function of weather, economic, demographic, and/or time variables. The estimated coefficients for the explanatory variables are then combined with projected values of those variables to calculate the forecasted number of customers and UPC, from which the total forecasted energy is calculated.

Weather data used in the long-term energy forecast model was collected from the National Oceanic and Atmospheric Administration (NOAA) for the Alpena County Regional Airport Weather Station. NOAA collects daily maximum and minimum temperature values from which cooling degree day (CDD) and heating degree day (HDD) values were calculated at different thresholds. For instance, a CDD 60 value indicates a cooling degree day with a 60-degree threshold and is calculated as CDD60 = Max {0, (MaxT + MinT)/2 – 60}. That is, the average daily temperature is calculated as the average of the maximum and minimum daily temperatures. The threshold value (60 °F) is subtracted from the average temperature and CDD60 is set to be the maximum of the result and zero. Similarly, HDD60 indicates a heating degree day with a 60=degree threshold and is calculated as HDD60 = MAX {0, 60 – (MaxT + MinT)/2}. The daily CDD and HDD values are then added up across the days of the calendar month.

CDD and HDD thresholds are chosen by distinct regression specifications for each customer class. The CDD and HDD values are intended to reflect the demand for cooling and heating, respectively, and are therefore used in the UPC regression specifications. The threshold value indicates the temperature at which cooling or heating is not needed. For example, a CDD60 threshold suggests that the customer does not have air conditioning or fan usage when the average daily temperature is below 60°F. The including of CDD and HDD and their associated threshold levels differ by customer class. The threshold level is identified by reviewing scatter plots of average temperature versus energy sales. For example, the CDD threshold is selected as the temperature at which usage begins to increase as the average daily temperature increases. Alternative CDD and HDD threshold levels are also evaluated according to their sign and statistical significance in a customer class's regression specification.

The Economic and demographic data used in the models were obtained from Woods and Poole Economics Inc. (W&P) for Alpena County, Michigan. W&P tracks historical data back to 1969 and provides projected values through 2060. The economic variables include employment and gross regional product (GRP) while the demographic variable of interest is population. These variables were included in models, where appropriate, based on statistical significance, explanatory power, and theoretical justification. For example, employment is used to explain UPC for the Residential class while GRP is used to explain UPC for the General Service Class. The W&P data is provided annually while all other data used in the regression is monthly; therefore, 12-month moving averages for the W&P economic and demographic variables are used to reduce annual discontinuities.

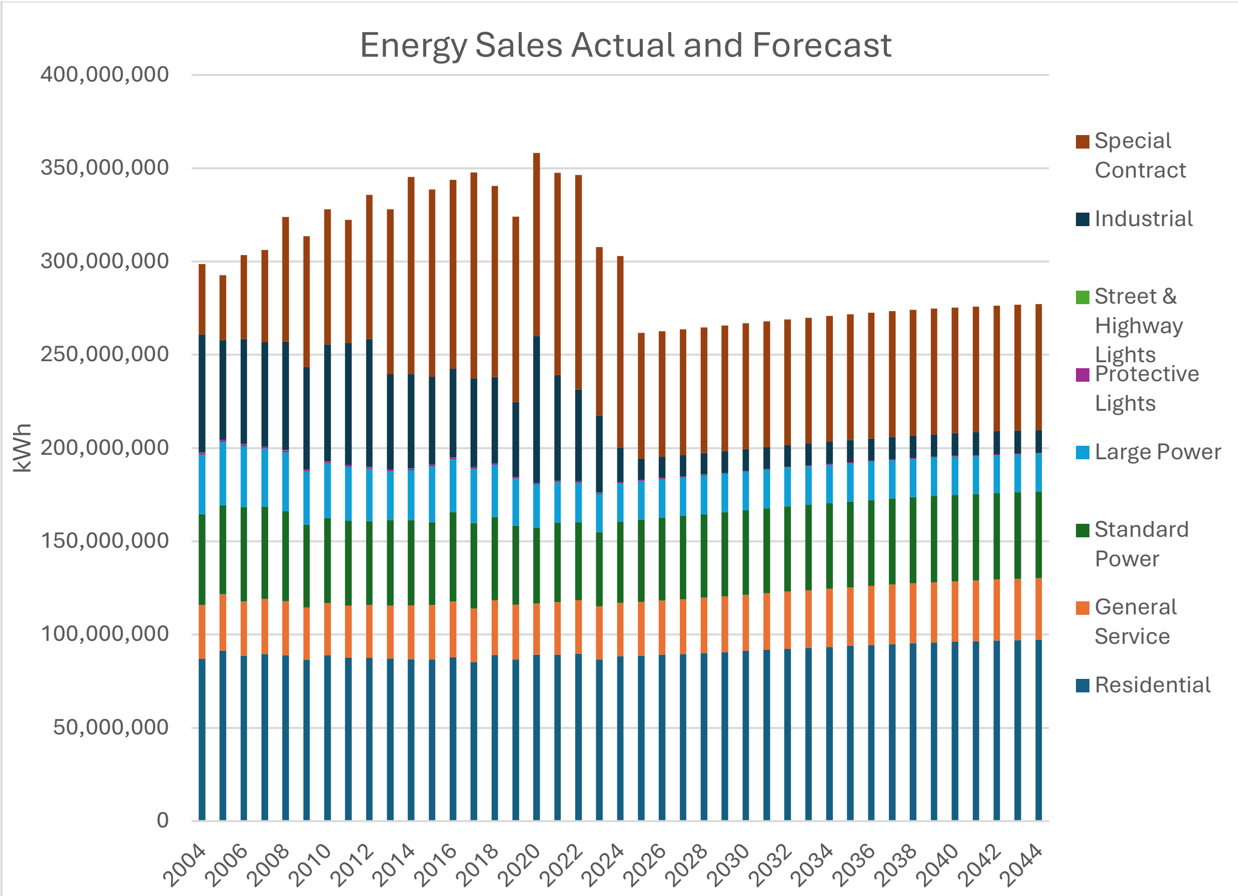

Figure 45: Energy Sales by Customer Class

Energy sales increased during the period from 2004 to 2020, primarily driven by sales increases to a single special contract customer. Sales began to decline in 2021 and are expected to bottom in 2025, main causes are reduction in sales to the special contract customer as a large behind the meter renewable project[10] comes online and the announced closure of an industrial customer in 2024. The combination of sales to the Residential, General Service, and Stands Power classes was relatively flat from 2004 to 2024 and is expect to see marginal increases in the next 20 years.

The long-term forecast of demand is created from models of APC's coincident peak (CP) for the system as well as the non-coincident (NCP) for specific customer classes. The CP indicates the amount of energy sold during the hour when APC's system peaked over a specified period. The monthly CP demand is modeled for the system excluding APC largest customers and then separately for each of these large customers. The summation of these CP forecasts provides a total system forecast of CP demand. The NCP indicates the

[10] https://www.holcim.us/alpena-solar-announcement

maximum amount of hourly energy sold for a customer class or customer within a specified period (e.g. monthly).

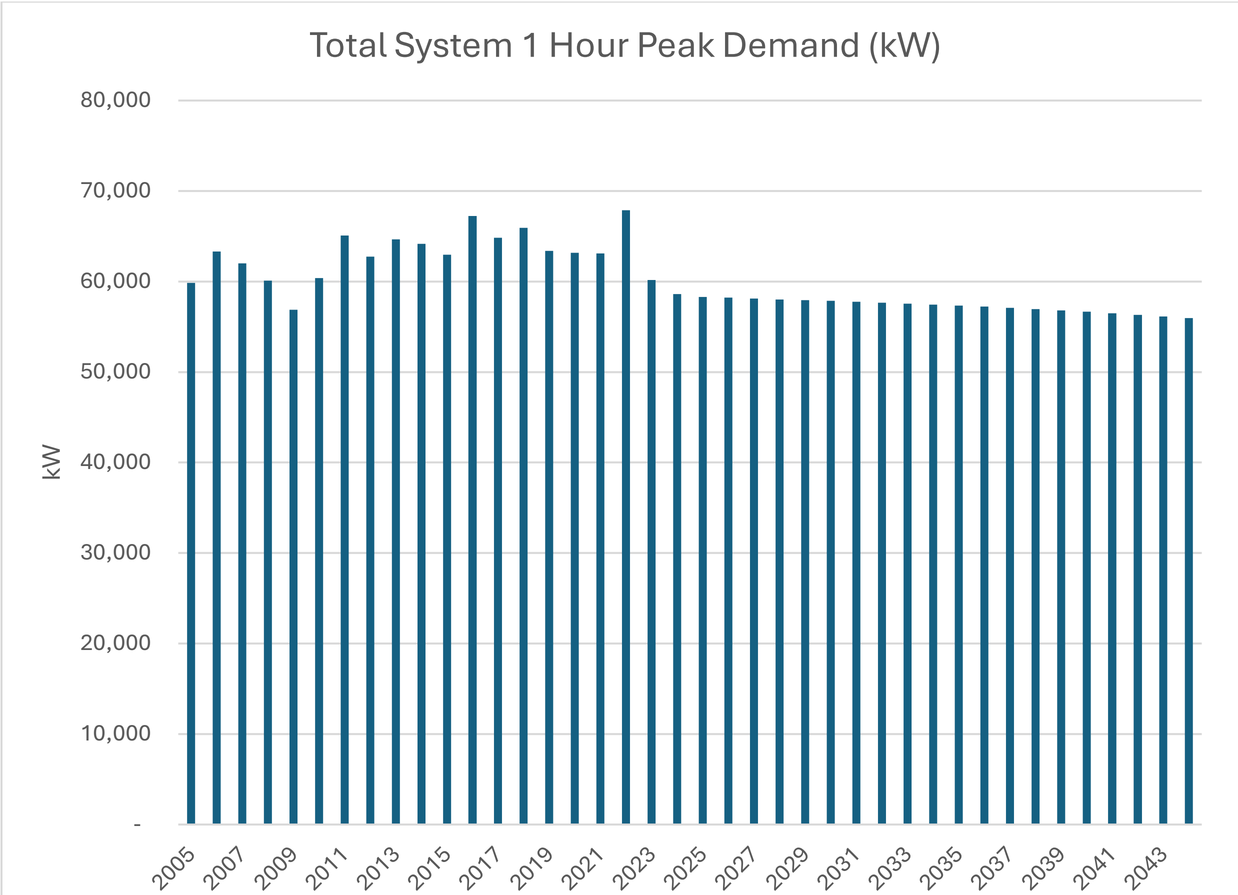

Figure 46: Annual Peak Demand

Total system demand increased steadily from 2004 to 2022 following the trend in energy sales. Demand began to decrease with energy sales and is expected to continue the declining trend for the next 20 years.

5. State of the Distribution System

5.1. System Overview

The APC electrical system is comprised of the following:

- One 138 kV & 34.5 kV subtransmission substation
- Two 138/34.5 kV subtransmission substations
- Eighteen 13.2 kV distribution substations (4 are customer dedicated)
- One 4.16 kV distribution substation (customer dedicated)
- Forty distribution circuits (5 are customer dedicated, and one backup without customers)

- Approximately 16,700 metered services
- 656.2 miles of overhead distribution and subtransmission line
- 72.1 miles of underground distribution and subtransmission line
- 2023 Peak demand of 60.2 MW
- 2023 Energy 307,677 MWh

APC's subtransmission and distribution system are constructed with levels of redundancy and capacity that allow for great flexibility in the operation of the system. All substations and circuits are backed up by other substations and circuits, with the capacity available to tie circuits together in outage situations or for maintenance.

Reclosing of circuit breakers and reclosers is utilized in some form or another within the entire system to allow momentary faults to clear to keep service available to as many customers as possible. It is understood that these momentary outages are becoming less desirable in our modern electricity driven world. However, APC does not have the ability to monitor and report statistics and indices on momentary outages.

APC also has a compact service territory in comparison to other investor-owned utilities and can quickly dispatch operations personnel to any area within a relatively short time frame. Because of this, a fuse blow scheme offers minimized momentary outages for the bulk of APC's customers while isolating the interruption to the smallest practicable area possible.

APC's entire system is SCADA controlled and monitored. The real time data and supervisor control of the system allows APC personnel to be notified of faults when they happen, analyze the wave form of the fault and system loading, and quickly take whatever action is necessary to resolve the issue.

5.2. Subtransmission System Voltages

APC's main electrical system is served by one 138 kV, grounded wye configuration transmission source owned by Michigan Electric Transmission Company (METC). The METC owned 138 kV switchyard has three feeds into APC's main interconnection substation. The METC switchyard was originally constructed in 1956 and construction is currently underway by METC to replace the switchyard at an adjacent location. The construction plan includes adding a 4th 138 kV feed into the station to increase reliability and resiliency.

APC operates its own subtransmission system with 12.6 circuit miles of 138 kV grounded wye overhead lines and 69.5 circuit miles of overhead and underground 34.5 kV ungrounded delta line. Only 1.2% of the 34.5 kV is installed as underground cable. The entire 34.5 kV system and part of the 138 kV system is built with redundant loops and is operated at a reduced capacity in normal configurations so that in a contingency situation there is adequate capacity and options built in.

5.3. Distribution System Voltages

At the distribution level, APC operates primarily a 13.2 kV grounded wye distribution system. The only three exceptions to this are three customer specific industrial substations where the customer takes service from the substation at 4.16 kV wye, 13.8 kV delta, and 34.5 kV delta voltages. By current count, APC operates 574.9 circuit miles of overhead and 74.3 circuit miles of underground distribution line. A total of 11.0% of the 646.2 circuit miles is underground cabling. Much like the Subtransmission system, the distribution circuits are also operated at a reduced capacity in normal situations. Circuits have at minimum one adequate backup, and many have multiple options for alternative feeds to give options for substation and line maintenance. This brings greater flexibility and resilience to the operation and maintenance of the distribution network, and it allows for reduced risks for operations personnel by allowing for more deenergized work where possible.

5.4. SCADA

APC operates a Supervisory Control and Data Acquisition (SCADA) system through an on-site server, software and maintenance support provided by Schneider Electric. This allows communication to 68 different Remote Terminal Units (RTUs) at 22 substations. A majority of the RTU are connected through APC owned fiber while a few remote locations are connected through a secure wireless connection. Within those substations several RTUs are connected and communicate with several types of relays.

These RTUs allow for monitoring of faults, equipment monitoring of alarms, control of reclosers/breakers, voltage regulators/load tap changers and metering electrical quantities. With this information APC has the ability to diagnose fault locations, timing of recloser and relay operations, understand system loading and view historical data. SCADA also provides the means for emergency operations of opening/closing breakers and reclosers, access to fault wave analysis without having to go to the device and providing status of the electrical system.

5.5. Outage Management

APC implemented an outage management system (OMS) in August of 2022. Prior to that, outage minutes were calculated by hand using system maps and spreadsheets. Milsoft' s software was chosen for the OMS as it also provided the use of advanced mapping and modeling functions while maintaining a single system map/model. Paper map books that were almost immediately out of date upon printing are no longer needed as operations personnel have access to up to date mapping data via phone or a connected tablet. Outage causes in the OMS system match the 10 general categories defined in Section 4.4 of the

IEEE Standard 1782-2022 the IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events. APC also uses the Interruption Subcategories from Section 4.5 along with the Affected Equipment and Contributory Factors from section 4.6 and 4.7 respectively. It was decided to input as much of the additional data beyond the outage cause to better analyze system performance and opportunities for substantial improvement at relatively low cost. Improvements in reliability come at a cost to achieve a given benefit, and as you near 100% reliability, the costs become greater to make smaller incremental improvements. Using data driven decision-making enables APC to make improvements where cost effectiveness provides the greatest outcomes for the ratepayers.

5.6. Distribution System Assets

5.6.1. Conductor and Equipment Ratings

Alpena utilizes ratings for three system conditions:

1. Normal – All substation transformers and distribution circuits in service, bus tie and tie switches open
2. First Contingency – One substation transformer, distribution circuit breaker or recloser out of service, bus tie switch/circuit tie switch closed. No loss of customers
3. Second Contingency – Two substation transformers, distribution circuit breakers or reclosers out of service, bus tie switch/circuit tie switch closed. Loss of customers.

Substation equipment including high-side (138 kV or 34.5 kV) transformers, breakers, tie switches, etc. Will be allowed to operate at 50% of maximum nameplate rating for normal conditions, 90% for 1st contingency outages, and 100% for 2nd contingency outages. Low side (13.2 kV) substation equipment and distribution circuit conductor, regardless if overhead or underground, will be allowed to operate at 60% of maximum nameplate or thermal rating for normal system conditions, 100% for 1st contingency outages with no reserve for 2nd contingency outages. The equipment and conductor ratings established are goals for APC to achieve and are part of the basis for the distribution plan.

Maximum ratings for substation equipment are provided by the manufacturers and are listed on equipment nameplates. Due to the expense and lead time associated with substation transformers and equipment, maximum continuous loading should not exceed nameplate ratings. Short term overloads in emergency situations can be handled by transformers with little or no damage based on percentage of overload and emergency loading duration.

Overhead conductor ratings are more difficult to establish than equipment ratings since the calculations include thirteen variables including selecting maximum temperature. The ampacity (thermal) ratings of overhead conductor on Alpena's system were determined by the following variables:

- 104 °F (40 °C) Ambient Temperature
- 167 °F (100 °C) Conductor Temperature (Normal, 1st Contingency & Emergency)
- 2ft/sec wind speed (utility standard)
- Additional eleven variable using a conservative approach

Alpena's standard Aluminum Conductor, Steel Reinforced (ACSR) is not a high-temperature conductor. It is rated for 167° F continuous operation and 212 °F emergency operation for a total of 1,500 hours over the conductor life. Additionally, system design (sag & clearances) must reflect this rating. Conductor sag at 212 °F is often not factored into overhead distribution circuit design therefore a more conservative rating (167 °F) is prudent to be used for normal system conditions. Under emergency conditions, conductors will be allowed to operate at 130% of their normal rating for up to four hours.

Underground conductor ratings are based on cable characteristics and installation methods based on conductor size.

- 90 °C Conductor Temperature (Normal and 1st Contingency)
- 105 °C Conductor Temperature (Emergency Rating)
- 20 °C Earth Ambient Temperature
- 75% Load Factor
- Conductors up to #4/0 AL 15 kV 1/3rd Concentric Neutral – direct buried, one circuit
- Large conductors, including tape-shield power cable – direct buried conduit, one circuit
- 133%, EPR conductor insulation

5.6.2. Substation Loading

Considering under 1st contingency outage conditions, that no loss of service to customer will be allowed, substation transformer capacity must be sufficient to support the loss of a single substation power transformer on the system under peak load conditions. Substation transformers will be allowed to be loaded up to 50% of the nameplate rating under normal operating conditions. Under 1st contingency outage condition, the transformer will be allowed to operate at 90% of maximum rating. This provides capacity for short-term spikes in load, unplanned load growth, and additional load transfer in the event of a 2nd contingency condition.

During the past three years only two of the 19 distribution substation transformers have exceeded the 50% limit during the system peak hour. The Hospital Substation transformer peaked at 54% of nameplate rating, however since this transformer is customer dedicated and not a backup for other substations there is not a need to address at this time. The second transformer that exceeded the 50% limit is the Northeast Substation transformer that peaked at 52%. Since the loading is marginally above the limit the transformer will continue to be monitored for load. The distribution substation transformer loading during peak hour for years 2021 to 2023 is shown in the following figure:

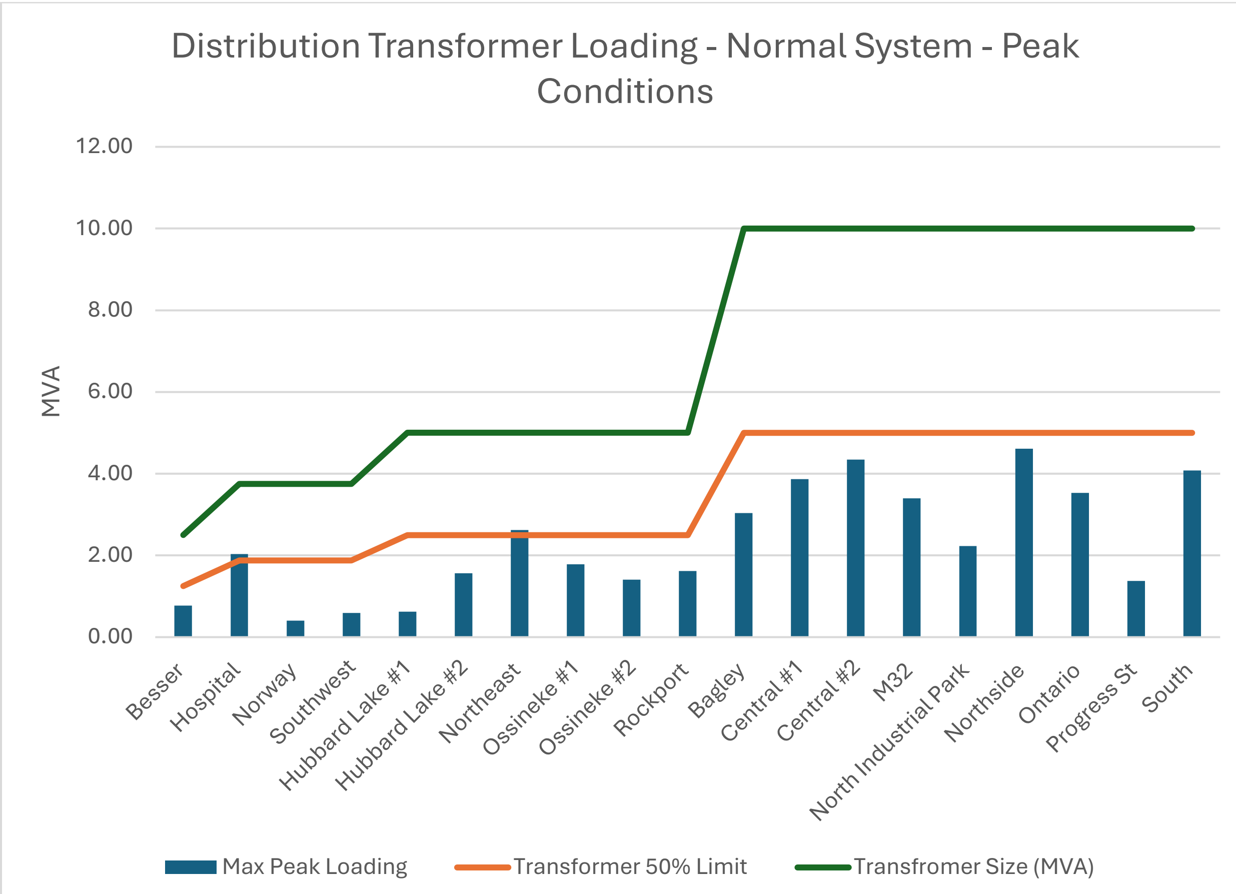

Figure 47: Distribution Substation Transformer Peak Loading 2021 – 2023, Normal Conditions

When comparing Alpena's total load to the total available capacity of distribution substation power transformers, Alpena's electric distribution system is currently loaded to 31.4% of total nameplate capacity.

Under all conditions (normal, 1st contingency, and emergency) none of Alpena's distribution substation transformer approached the 90% limit in 2023 or on a 5-year average basis. The highest transformer demand was 64% at the Northeast Substation. The peak distribution substation transformer loading for 2023 and the 5-year average is shown in the following figure:

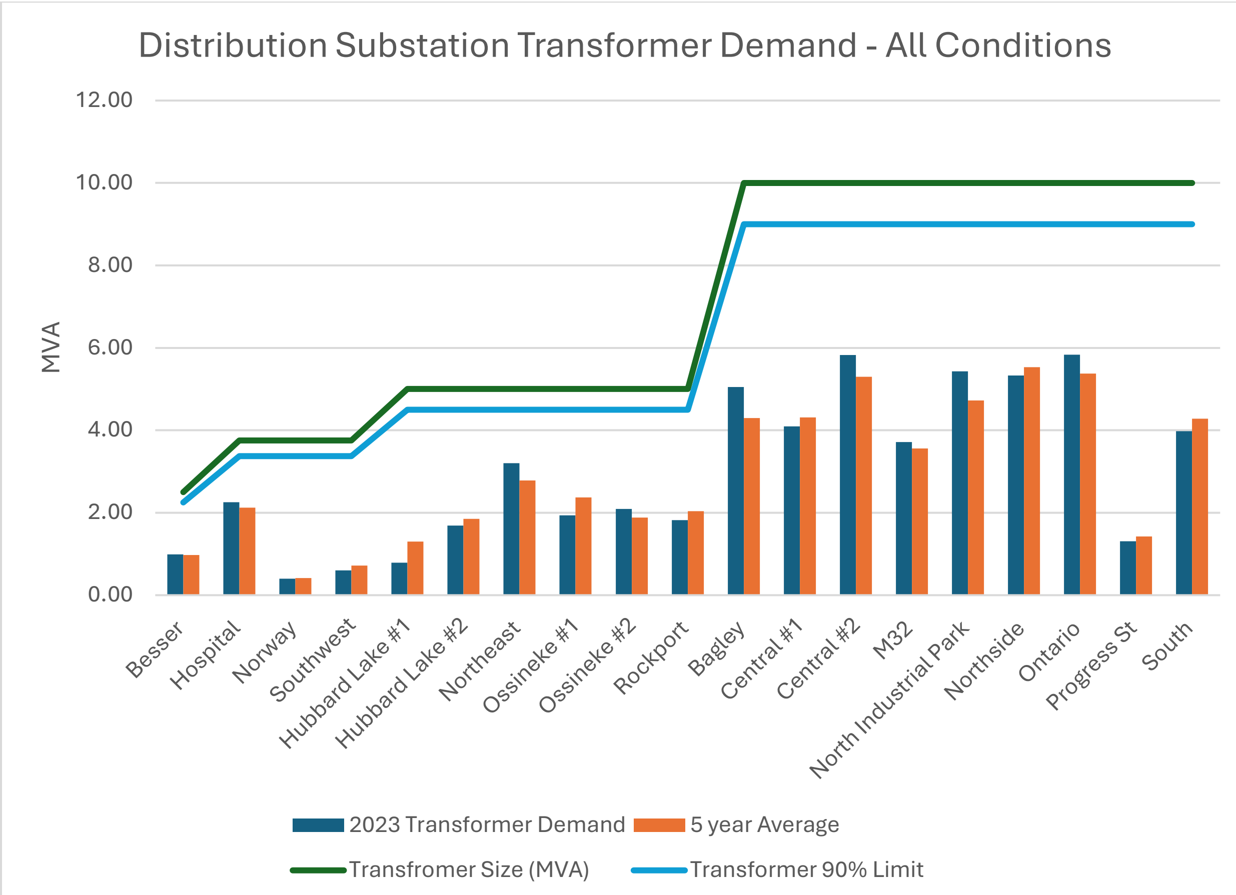

Figure 48: Distribution Substation Transformer Loading 2023 & 5-Year Average - All Conditions

During the past three years only one of the 5 subtransmission substation transformers have exceeded the 50% limit during the system peak hour. The Lafarge Substation transformer peaked at 76% of nameplate rating, however since this transformer is customer dedicated and not a backup for other substations there is not a need to address at this time. The subtransmission substation transformer loading during peak hour for years 2021 to 2023 is shown in the following figure:

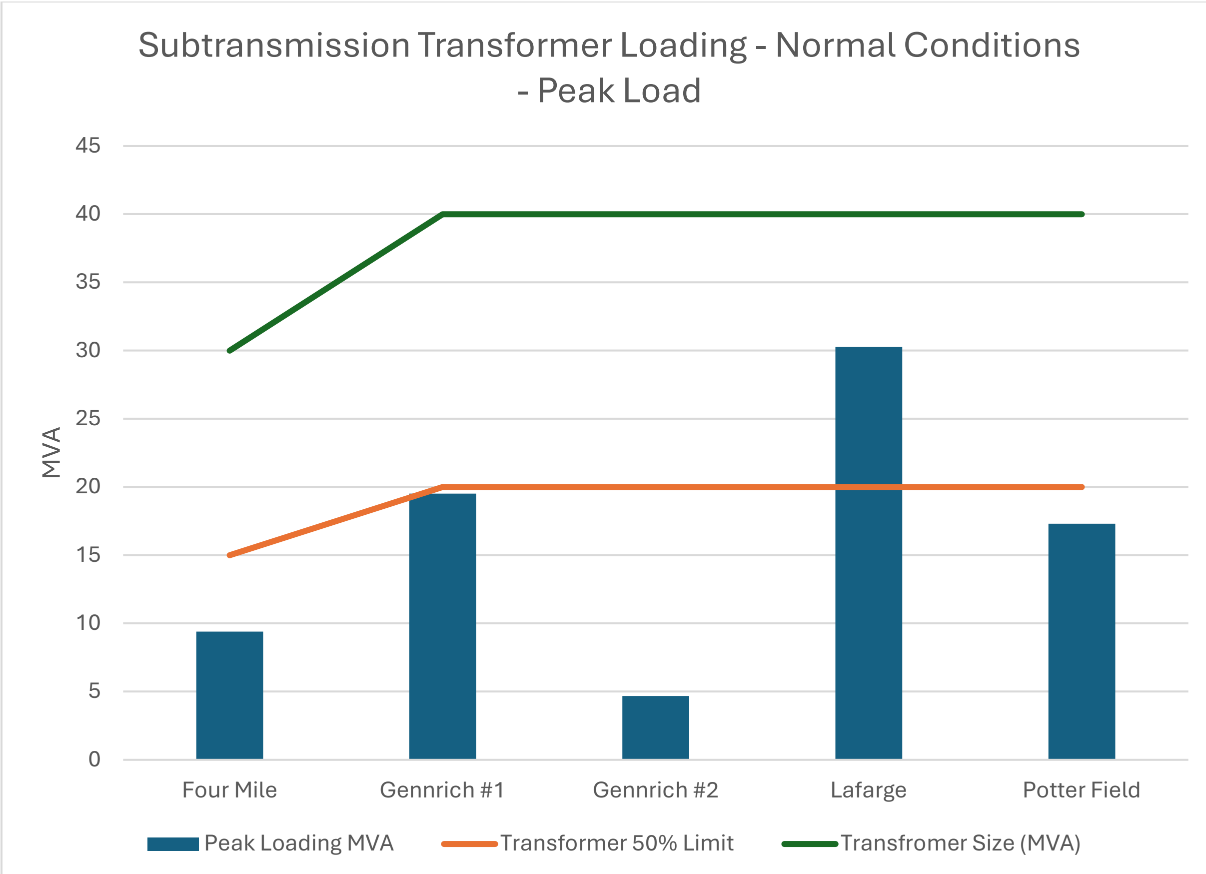

Figure 49: Subtransmission Transformer Loading – Normal Conditions

When comparing Alpena's total load to the total available capacity of subtransmission substation power transformers, Alpena's electric subtransmission system is currently loaded to 40.1% of total nameplate capacity.

Under all conditions (normal, 1st contingency, and emergency) none of Alpena's subtransmission substation transformer exceed the 90% limit in 2023 or on a 5-year average basis. The highest transformer demand was 89% at the Lafarge Substation. The peak subtransmission substation transformer loading for 2023 and the 5-year average is shown in the following figure:

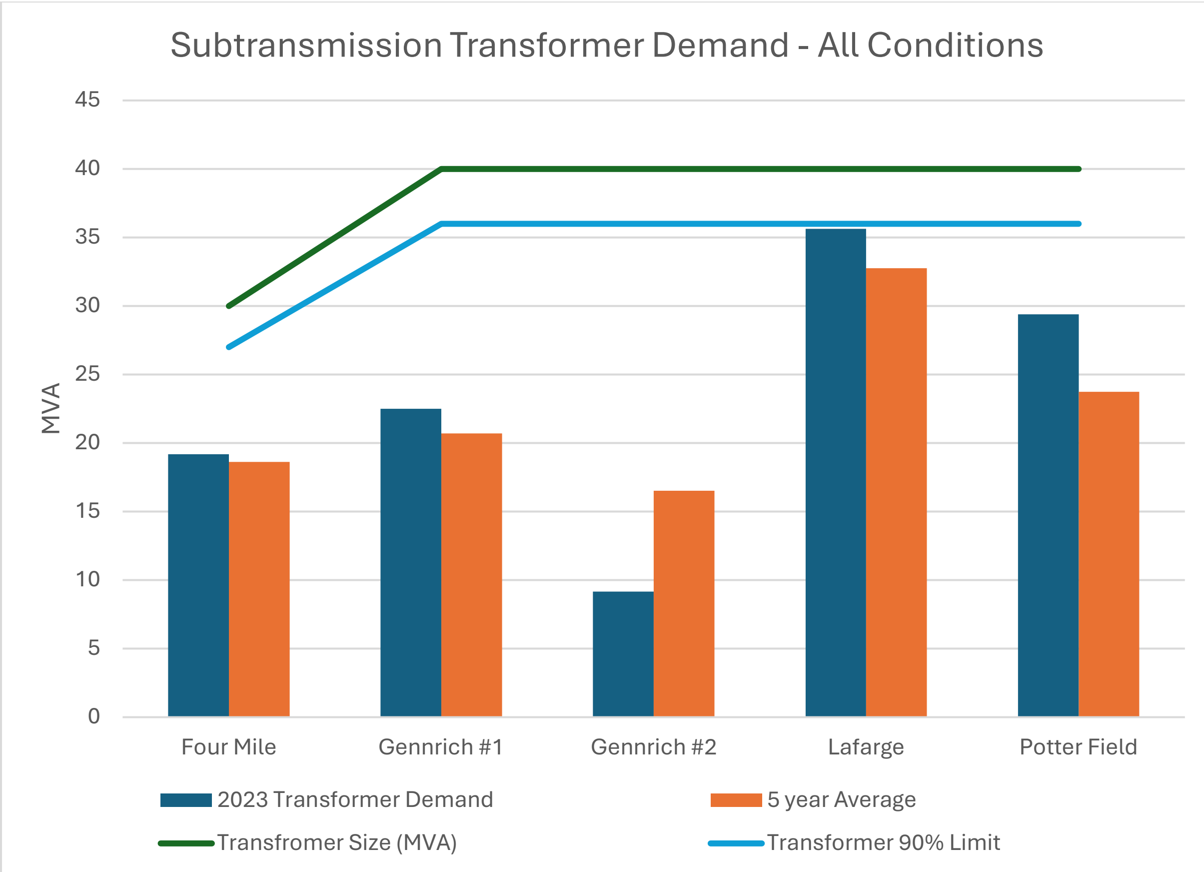

Figure 50: Subtransmission Substation Transformer Loading 2023 & 5-Year Average - All Conditions

5.6.3. Circuit Loading

Consistent with the substation transformer outage conditions, no loss of service to customers will be allowed under 1st contingency distribution circuit recloser or main circuit outage conditions. This applies to mainline sections of distribution circuits. Alpena's distribution circuits all have normally open tie points to other circuits. Limiting distribution circuit loading to 60% of mainline conductor ampacity allows for one distribution circuit to be out of service and backup circuit to carry nearly all of load under peak system conditions, assuming both circuits have the same conductor and are loaded to 60%. Under 1st contingency outage condition the conductor will be allowed to operate at 100% of its thermal rating. Short-term spikes in load will be covered by utilizing the emergency conductor ratings.

Based on 2023 peak day load conditions, none of Alpena's thirty-four, noncustomer dedicated or backup, distribution circuits are operating above their 60% rating. The heaviest loaded circuit is Circuit #4, Fletcher St., is loaded to 48% of its mainline conductor rating. The circuit loading for all circuits is contained in the following figure:

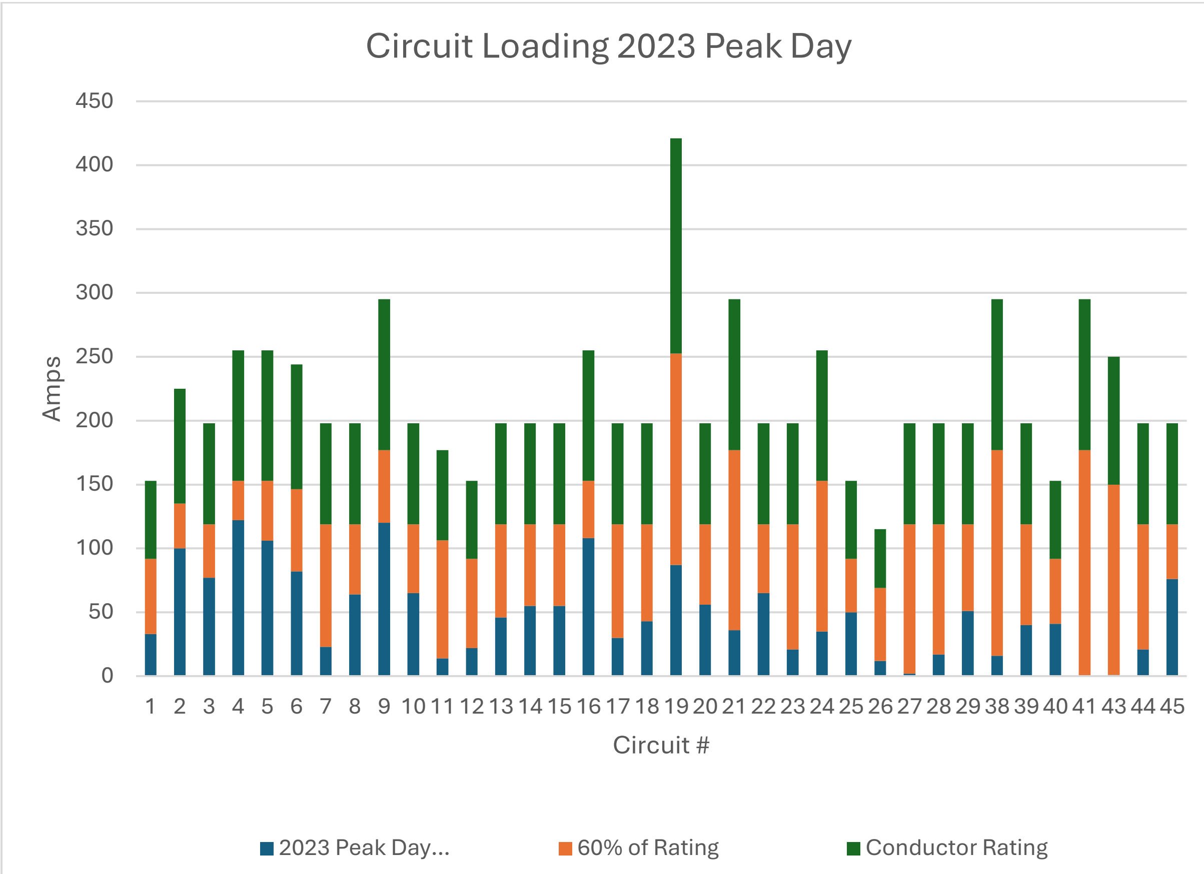

Figure 51: 2023 Peak Circuit Loading

5.6.4. Circuit Contingency Analysis

As previously mentioned, Alpena limits distribution system loading to 60% of mainline conductor capacity to allow for one distribution circuit to be out of service and a backup circuit to carry nearly all load under peak system conditions. All of Alpena's circuits have at least one backup with adequate capacity for peak day loading. The following table shows the available circuit backups, their mainline circuit capacity, and the total loading in 1st contingency situations.

Circuit Out of Service	Backup Circuit	Circuit Out of Service Load	Backup Circuit Load	Total Load	Backup Circuit Conductor Capacity	Backup Circuit Loading
1	15	33	55	88	198	44%
1	45	33	76	109	198	55%
2	3	100	77	177	198	89%
2	19	100	87	187	421	44%
3	2	77	100	177	225	79%
3	5	77	106	183	255	72%
4	16	122	108	230	255	90%
5	3	106	77	183	198	92%
5	18	106	43	149	198	75%
5	19	106	87	193	421	46%
6	15	82	55	137	198	69%
7	8	23	64	87	198	44%
7	28	23	17	40	198	20%
7	26	23	12	35	115	30%
8	7	64	23	87	198	44%
8	26	64	12	76	115	66%
8	39	64	40	104	198	53%
9	44	120	21	141	198	71%
9	18	120	43	163	198	82%
9	23	120	21	141	198	71%
9	43	120	1	121	250	48%
10	41	65	0	65	295	22%
10	38	65	16	81	295	27%
10	13	65	46	111	198	56%
11	13	14	46	60	198	30%
11	14	14	55	69	198	35%
12	14	22	55	77	198	39%
12	22	22	65	87	198	44%
13	16	46	108	154	255	60%
13	14	46	55	101	198	51%
13	11	46	14	60	177	34%
13	10	46	65	111	198	56%
14	12	55	22	77	153	50%
14	13	55	46	101	198	51%
15	1	55	33	88	153	58%
15	45	55	76	131	198	66%
15	16	55	108	163	255	64%
15	41	55	0	55	295	19%

Circuit Out of Service	Backup Circuit	Circuit Out of Service Load	Backup Circuit Load	Total Load	Backup Circuit Conductor Capacity	Backup Circuit Loading
16	4	108	122	230	255	90%
16	13	108	46	154	198	78%
16	15	108	55	163	198	82%
17	45	30	76	106	198	54%
18	5	43	106	149	255	58%
18	9	43	120	163	295	55%
19	2	87	100	187	225	83%
19	5	87	106	193	255	76%
19	24	87	35	122	255	48%
19	40	87	41	128	153	84%
20	21	56	36	92	295	31%
20	39	56	40	96	198	48%
21	20	36	56	92	198	46%
21	39	36	40	76	198	38%
22	12	65	22	87	153	57%
23	9	21	120	141	295	48%
24	19	35	87	122	421	29%
24	26	35	12	47	115	41%
25	40	50	41	91	153	59%
26	7	12	23	35	198	18%
26	8	12	64	76	198	38%
26	24	12	35	47	255	18%
27	28	2	17	19	198	10%
27	29	2	51	53	198	27%
28	27	17	2	19	198	10%
28	7	17	23	40	198	20%
28	44	17	21	38	198	19%
29	27	51	2	53	198	27%
38	10	16	65	81	198	41%
38	45	16	76	92	198	46%
39	20	40	56	96	198	48%
39	21	40	36	76	295	26%
40	19	41	87	128	421	30%
40	25	41	50	91	153	59%
41	10	0	65	65	198	33%
41	15	0	55	55	198	28%
43	9	1	120	121	295	41%
43	45	1	76	77	198	39%

Circuit Out of Service	Backup Circuit	Circuit Out of Service Load	Backup Circuit Load	Total Load	Backup Circuit Conductor Capacity	Backup Circuit Loading
44	9	21	120	141	295	48%
44	28	21	17	38	198	19%
45	43	76	1	77	250	31%
45	38	76	16	92	295	31%
45	1	76	33	109	153	71%
45	15	76	55	131	198	66%

Table 1: Circuit Backup Analysis

5.6.5. Subtransmission System

5.6.5.1. Substation Power Transformers

APC operates four power transformers at three different substations on the APC operated 138 kV Wye to 34.5 kV Delta system. Each transformer is equipped with a Load Tap Changer (LTC) with a Beckwith 2001 B or C LTC controller for voltage regulation. A multitude of alarms are equipped on each transformer and monitored by SCADA. All transformers have protective relaying which includes over current and phase differential. The average age is 21 years with the oldest from 1986 and the newest in 2020

	Substation	Rating	HV/LV	Type	Date	LTC
1	Four Mile	18/24/30 MVA	138 kV Wye/34.5 Delta	OA/FA/FA	1986	Y
2	Gennrich #1	24/32/40 MVA	138 kV Wye/34.5 Delta	KNAN/KNAF/KNAF	2020	Y
3	Gennrich #2	24/32/40 MVA	140 kV Wye/34.5 Delta	ONAN/ONAF/ONAF	2003	Y
4	Potter Field	24/32/40 MVA	138 kV Wye/34.5 Delta	ONAN/ONAF/ONAF	2004	Y

Table 2: Subtransmission Substation Power Transformers

5.6.5.2. Circuit Breakers

A circuit breaker is an electrical device designed to protect assets from damage due to excess current. APC has 17 circuit breakers across three substations on the 138 kV as well as the 34.5 kV system. A mixture of Oil, SF6, and Vacuum breakers are employed on the system. All circuit breakers are connected to relaying with over current and reclosing protection. The average age of APC circuit breakers is 18 years with the oldest from 1965 and newest from 2021. Most circuit breaker manufacturers list an average of 10,000 operations for useful life. APC average operation count is 385.

Quantity	Type	Voltage Rating	Current Rating	Short Circuit Rating
2	Oil Breaker	145 kV	1200 A	21 kA
2	SF6 Breaker	145 kV	2000 A	40 kA
5	Vacuum Breaker	38 kV	1200 A	25 kA
8	Vacuum Breaker	38 kV	1200 A	31.5 kA

Table 3: Subtransmission Circuit Breakers

5.6.5.3. Circuit Switchers

A circuit switcher is a device that interrupts power flow and is installed on the high voltage side of a power transformer. APC operates three SF6 circuit switchers at two substations. All circuit switchers are connected to protective relaying for current differential tripping to isolate the transformers from faults. The average age of the circuit switchers is 19 years old, the oldest being 2002 and the newest 2007. Average operations between the three circuit switchers are 151 operations during their lifetime.

5.6.5.4. Subtransmission Poles and Pole Top Equipment

APC owns approximately 1,200 subtransmission poles. Of those poles, 80% are wood with the remainder being wood pole equivalent galvanized steel. APC has records of when the 138 kV and 34.5 kV subtransmission lines were built, and subsequently rebuilt. Based on those records, the average age of APC subtransmission poles is 33 years old with the oldest pole line at 67 years old which is currently being rebuilt.

Subtransmission pole top hardware is mainly categorized by the insulation style and rating. Of the subtransmission poles, 20% have wood crossarms supporting arm pin porcelain insulators, 40% are equipped with porcelain post insulators, and the remainder equipped with polymer post insulators. The porcelain insulators are 35 kV rated while the polymer insulators are rated either 69 kV or 138 kV, depending on the future possibilities for the respective line.

Whenever maintenance or capital construction is being done on any part of the subtransmission system involving insulation, APC takes the opportunity to replace aging porcelain insulators with polymer. The risk is that over time porcelain cracks, producing the opportunity for tracking. Once tracking occurs, a pole fire is the likely result. A larger scale re-insulation project was completed under the maintenance plan in 2022 on one of the 34.5 kV lines running through the city from Gennrich Substation to one of APC's industrial customers where all the aging porcelain insulators were converted to polymer.

5.6.5.5. Grounded Phase Detection

A major improvement to the subtransmission system began in 2015 with the implementation of grounded phase detection at one of APC's three 34.5 kV substations. As previously covered, APC operates its 35 kV subtransmission in an ungrounded delta configuration. This means that all three phases are tied to each other through the transformer coils as opposed to being tied to ground through the transformer coils. The largest benefit to operating in a delta configuration is that the system will still operate, albeit less efficiently, if one phase becomes grounded between substations. The risk in switching operations comes when differing phases on separate substations could be grounded, thus leading an operations worker to close a switch by hand into a dead fault at the 35 kV level and drop all load served by the two circuits. Previously, APC would send operations personnel with high voltage live line voltmeters quarterly to see if any of the phases had become grounded. The implementation of the Grounded Phase Detection system mitigated two risks to operations personnel by removing the risk of closing into a dead fault and having to check for grounded phases with live line tools. Tying either of the other two subtransmission substations to the one with the grounded phase detection would immediately alarm via the SCADA system. This would cause a temporary pause in switching, and a plan to patrol the affected substation lines for the ground or a new switching order to be implemented to narrow down the affected line and reduce patrolling time. The second subtransmission substation received the grounded phase detection system in 2021. The final subtransmission substation has two transformers that operate independently and do not currently have any space available to easily install the two sets of potential transformers required to have grounded phase detection on every subtransmission bus. A project to add additional structure for the east half of the substation and install the grounded phase detection system is slated for 2027. The installation of the additional structure on the west half of the substation is planned for 2029. This will then complete the installation of the grounded phase detection system on all the APC delta configured substations.

5.6.6. Distribution System

5.6.6.1. Substation Power Transformers

APC operates 19 power transformers at 13 distribution substations sites and 3 customer specific sites. Voltage regulation varies between Load Tap Changers (LTC) and voltage regulators at the substation based upon circuit loading. Most of the transformers are 34.5 kV Delta to 13.8 kV Wye. Two customer sites are different as they are 34.5 kV Delta to 4.16 kV Wye and 138 kV Wye to 13.8 kV Delta.

The average age is 18 years with the oldest being 1979 and the newest being 2023. APC has bought new transformers, remanufactured transformers, and sent older existing transformers out to be reconditioned over the last several years. Reconditioning involves rewinding the core, new insulation and updating electrical components. Lead time for new transformers and pricing increases have affected when and where APC purchases transformers.

Quantity	Size	LTC
1	2.5 MVA	N
3	3.75 MVA	Y
5	5 MVA	Y
4	10 MVA	N
5	10 MVA	Y
1	40 MVA	Y

Table 4: Distribution Substation Power Transformers

5.6.6.2. Substation Reclosers

APC operates 41 substation reclosers at 13 different substation sites plus four customer specific sites. A mixture of manufacturers has been used with several different variants. The average age is 14 years with the oldest being from 1994 and the newest from 2023. Most manufacturers rate their reclosers for 10,000 operations but varies with load current. APC has an average recloser operation count of 132.

A mixture of manufacturers has been used for the controllers used on these reclosers. Different reclosers are being assessed to determine the best solution based upon lead time and pricing. This has directed APC to look at different manufacturers than what is currently being used.

In the past decade APC has experienced three recloser failures while in service. One variant recloser has been phased out and the other variant is scheduled to be phased out by 2025.

5.6.6.3. Poles and Pole Top Equipment

APC owns almost 19,000 distribution poles. APC utilizes all wood poles for the distribution system, primarily cedar and pine. Of the 19,000 poles, 30% are constructed as 3 phase assemblies utilizing a crossarm and compatible hardware. Class 4 or better are utilized for primary poles and Class 6 or better are utilized for secondary poles depending on the number of contacts and loading.

Like the subtransmission equipment, all new insulation is polymer or plastic as APC has completely moved away from porcelain insulation. Porcelain insulators have been proven to crack, which leads to tracking and eventually a pole fire. These cracks are typically imperceptible, making it very hard to prevent tracking issues and the pole fires it causes. APC replaces all porcelain insulators with polymer or plastic when doing maintenance and capital construction on the distribution system.

APC line personnel are currently working through a multi-year project to replace all porcelain cut-outs on the system. It is a systematic replacement, with the distribution system being targeted by circuit and segment thus reducing the risk of tracking and the pole fires that are the result.

5.6.6.4. Line Reclosers

APC operates four (4) three phase and fourteen (14) single phase line reclosers. The average age is 20 years with the oldest being from 1992 and newest in 2019. All line reclosers are hydraulically controlled and do not require a controller.

APC has started a Fault Location, Isolation, and Service Restoration (FLISR) project. This would place two (2) three phase and three (3) single phase reclosers additionally onto the system. These reclosers would be vacuum interrupter-based with electronic controllers.

5.6.6.5. Line Regulators

APC operates thirteen (13) single phase pole mounted line regulators on the system. Three of the regulators are stand by for contingency operation in the event a specific substation needs to be removed from service. This allows for voltage support from another substation. The average age is 24 years old with the oldest being estimated at 1970 and the newest from 2021. A mixture of control and model variants are used to control the voltage regulation. The average number of tap operations is 32,841.

APC has plans to replace older regulators in the next five years due to age and maintenance. Controls will also be replaced to standardize one controller to allow ease of use and maintenance.

5.6.6.6. Underground Residential Distribution

APC has been installing underground distribution cables since before 1980. Currently, APC has approximately 10.4 miles, about 13%, of the total underground on the system, of pre-1980 underground primary in service. All new cable is jacketed tree resistant cross-linked polyethylene (TR-XLPE) concentric neutral cable. Open concentric cables direct buried without utilizing a duct system in the very basic soil conditions in the area have led to complete loss of the concentric neutral conductors over time. This not only is a loss of the return path in a grounded wye system, but it also makes locating the cables underground harder for requests in the MISS-DIG system. This also has changed the installation techniques as all new cables are installed in an underground duct system or conduit system. This offers protection from the soil, ease of replacement, and some physical protection from dig in damage.

5.6.6.7. Metering Equipment

APC has over 16,700 active meters on the system for revenue metering. This includes single phase as well as poly phase meter setups. An Advanced Meter Reading (AMR) system has been in place since 2016. This allows for a single meter reader to drive by in a vehicle and collect data. Outside of the AMR system there are sixteen (16) polyphase meters which are read via cellular data and processed. All residential meters are capable of kWH readings. Other meters are capable of kWH, max kW, Power Factor, Time of Use (TOU) and bidirectional measurements.

An Advanced Meter Infrastructure (AMI) system is currently in review for 2029. This would allow for near real time information to be provided back to APC. Allowing for faster response time to outages, more accurate outage coordination of affected customers and other information to help identifying issues on the electrical system. Customers would also be provided with information regarding their electrical usage and be more informed of electrical usage and needs.

All meters are tested in accordance with Michigan Public Service Commission (MPSC) Technical Standards for Electric Service. APC has three-meter test devices which are calibrated annually and referenced against standards that are traceable to the National Institute of Standards and Technology (NIST). All meter testing is conducted by an APC meter worker throughout the year.

5.6.6.8. Line Transformers

APC utilizes line transformers to reduce the distribution voltage down to commercial and residential voltage. Currently, APC has 7,393 transformers in use by customers, 31 in use by APC, and 438 in inventory for a grand total of 7,862. There is 213.59 MVA of capacity in use by customers, 1 MVA in use by APC, and 37.48 MVA in inventory for a total of 252.07 MVA of capacity in those 7,862 transformers.

In 2023, APC focused on a goal of ensuring that our distribution system was completely free of any transformers containing Polychlorinated Biphenyl oil, or PCBs. Throughout the years, anytime APC line personnel encountered a transformer that contained PCB oil, it was swapped out for a non-PCB unit and the contaminated can was sent out for disposal. The focused effort in 2023 involved dedicating a crew to take generated lists of all transformers by circuit and having them inspect the units for a non-PCB label. If there was not labeled non-PCB, they took an oil sample to test for PCB. Currently, all circuits have been inspected and spot checks are being done to ensure that every unit on the system has been inspected. Completion of this project and certification that APC's distribution system is PCB-free is expected in December 2024.

APC employs substation technicians that also service and test line transformers. When a unit is changed out in the field, it comes back to the shop where it is tested, repaired, if necessary, painted, and returned to inventory. Live front, pad mount transformers are retired when they are swapped out in the field.

Starting in January of 2020, the transformer industry underwent a spectacular change where lead times and prices for new transformers went up by an astronomical margin. The industry saw price increases of over 400% for some sizes with lead times stretching out more than a year. APC consistently spent between $120,000 and $140,000 per year on new transformers up until 2020-2021. Now the spending is between $500,000 and $750,000 and that is mostly for remanufactured units. Also, APC specified stainless steel tanks for our pad mount transformers as we are in an area where there is heavy salt use in the winter. None of the transformers that are purchased now are stainless because they're not offered in remanufactured units, and they are priced too high in new units to be considered a prudent purchase.

Currently, APC quotes transformers multiple times per year and orders more inventory than has been typical in the past due to long and undependable lead times. This purchasing model allows APC to constantly check the market for reductions in cost, and by quoting many different companies, it allows APC to take advantage of surpluses in certain sizes that one company might have that another doesn't.

6. Distribution System Maintenance

6.1. Vegetation Management Program

Alpena Power Company is required by the Michigan Public Service Commission to trim trees and remove vegetation that exist in and around power line right of way to improve the safety, efficiency, and reliability of its power transmission and distribution system. Safety and service reliability for APC's customers, employees, and the public is the primary concern. Untrimmed trees and vegetation can result in outages, damage, injuries, and even deaths if not appropriately maintained.

APC must adhere to strict technical performance and reliability standards as set forth by the Michigan Public Service Commission. These standards ensure that rate paying customers receive the best possible service and reliability of power to their homes and businesses. Trees and vegetation are a major source of outages and therefore must be cut and trimmed in a manner that appropriately reduces the risk that they will contact an energized power line. Nearly one fifth of APC's power outages from 2023 were tree related, and because tree related outages typically take longer to restore, those outages accounted for one third of the total outage minutes for the year. By proactively managing and controlling the growth of trees and other vegetation near power lines, APC can prevent outages, reduce maintenance costs, and ensure a continuous supply of electricity to its customers.

APC has a total of 656 miles of overhead line and 72 miles of underground line to maintain throughout a mix of land types and water. The rolling hills and forested areas make it difficult to access certain spots requiring specialty equipment. Wetlands and rivers limit the use of heavy machinery, necessitating more manual labor or lighter, more versatile equipment. Additionally, the sandy and loamy soils making up parts of APC territory affects the stability and growth patterns of vegetation. Effectively managing vegetation on APC's distribution system means integrating various methods like mechanical trimming, herbicide application, manual removal, and mulching to achieve effective vegetation control while ensuring the safety and reliability of the power distribution system. By combining these practices strategically, APC can maintain compliance with regulations, reduce outage risk, and promote environmental stewardship.

6.1.1. Tree Trimming Program:

APC's Tree Trimming and Vegetation Management Plan consists of two primary activities: cycle-based cutting and trimming on a circuit/feeder basis, and hot spot trimming based on poor circuit performance or customer notification. Customers are encouraged to notify APC if they see a tree that poses a significant threat to the distribution system and those requests are handled on a case-by-case basis. Cycle-based circuit trimming and cutting is the most efficient method of tree trimming and APC strives to do as little hot spot trimming (out of cycle clearance trimming or danger tree cutting) as necessary. When hot-spot trimming is required, APC sub-contractors will make every effort to remove the tree in question, not just cut it back as historical analysis shows that the growth after trimming will not keep it out of the lines for more than one growing season. All work is performed by contract tree trimmers who are certified by the State of Michigan. Alpena supervisory employees manage the contract tree trimmers, prioritize, and schedule the work.

APC has determined that a 5-year circuit trimming cycle would provide the level of safety and service reliability expected by APC's customers. Looking at three years of data ending in 2021, APC cut an average of 77 miles of its 643 miles of overhead lines, with an average spend per year of $297,128. That adds up to a nine-year cycle to get across the system. It was also observed that the right of ways were not clear for the cycle time and tree related outages were significant in comparison to other outage causes. APC took immediate action to solve this issue.

In 2021, APC committed to a firm policy of ground to sky right of way clearing. Proper ground to sky right of way cutting means that all trees within the right of way are cut to the ground, with the larger pieces of wood left for the property owner and the smaller pieces chipped. Stumps are left as close to the ground as possible. Prior to 2021, total removal of trees in the right of way was not always consistently done, leaving some areas of circuits vulnerable to vegetation issues before the next trimming cycle came due. The following list outlines APC minimum and maximum easement trimming widths for the various types of line.

Line Type Clearance Limits / Easement Width

- Overhead Secondary/Service Drops 2.5' / 5'
- Underground (All) / 10'
- Overhead Primary Distribution 15' / 30'
- Sub transmission (34.5 kV) 25' / 50'
- Sub transmission (138 kV) 50' / 100'

The ground to sky requirement ensures that all vegetation within the entire right of way, including overhang, is managed properly. This type of cutting is much more expensive as it takes more time to go a mile removing trees than it does to go a mile just trimming them. APC committed to an 85% increase in tree trimming budget in 2021 and has been increasing that number every year. APC feels this financial commitment is necessary to get the system cut to the point where it can be maintained on a five-year cycle. Currently, APC is on a 7-year cycle time for ground to sky clearing of all its circuit right of ways. From the start of 2021 to the end of 2023, APC cut approximately 180 miles of overhead conductors, with a yearly spending average of $614,230. After two years of the new ground to sky strategy and factoring in the details of the specific circuits that were coming due for trimming, APC vegetation management personnel decided that a more aggressive approach was needed to reach the cycle trimming goals. In the year 2023 APC spent $620,544.55 and trimmed 53 miles of overhead line on the system, spending on average $11,744 per mile. These were circuits that were heavily wooded and took large amounts of manpower to get cleared. In the last 3 years the strategy for trimming was to start on the circuits in the south of our system and move clockwise going north. APC chose this path after carefully considering the length of time since the last trimming cycle along with using data to see where most of the tree related outages were occurring.

An average of 104.2 miles of overhead line needs to be cut every year until the 7-year cycle finishes in 2028. Over the next 5-year span APC plans to spend on average $943,420 per year with a total of $4,717,100 to be spent on distribution and subtransmission vegetation management in that time frame. After APC hits its goal with the 7-year full circuit easement clearing cycle, it will then move to the permanent 5-year cycle.

APC's service territory has a total of 656 miles of overhead lines and 72 miles of underground lines. With all the miles of line that need to be maintained, ground to sky clearing is the best way to ensure that each circuit gets trimmed every five years. APC strives to cut all right of ways ground to sky, but there are certain situations where that type of clearing is not feasible. One example of this would be some areas within city limits where both trees and power lines run along the street adjacent to the sidewalk. These situations are handled case by case, with the intent to ensure cutting and trimming is done to provide safe clearance for energized lines as well as ensure that the vegetation will not become an issue before the next trimming cycle.

The following table outlines APC's plan for the next 5 years of vegetation management. After 2028, APC expects to be on a permanent 5-year, full circuit cutting cycle.

Year 2024	Circuit	Miles	Last Year Trimmed	Condition	Estimated Cost
	10th Street	5.3	2018	Poor	$50,000
	Bloom Road	28.5	2016	Poor	$256,500
	East Long Lake	17.6	2016	Poor	$193,600
	Grand Lake	20.5	2016	Poor	$225,500
	34.5 KV	10		Average	$50,000
		81.9			$775,600

Year 2025	Circuit	Miles	Last Year Trimmed	Condition	Estimated Cost
	Grand Lake	24	2016	Poor	$264,000
	Palm Street	8	2016	Poor	$64,000
	West Long Lake	43	2016	Poor	$473,000
	French Road	7.6	2015	Poor	$83,600
	34.5 KV	10		Average	$50,000
Totals		92.6			$934,600

Year 2026	Circuit	Miles	Last Year Trimmed	Condition	Estimated Cost
	8th Street	7.9	2018	Average	$86,900
	North Industrial Park	6.1	2016	Average	$48,800
	King Settelment	35.7	2015	Poor	$236,200

	Hillman	16.2	2015	Average	$129,600
	South shore	20.8	2019	Average	$208,000
	M32 West	15.8	2018	Average	$142,200
	34.5 KV	10		Average	$50,000
Totals		112.5			$901,700

Year 2027	**Circuit**	**Miles**	**Last Year Trimmed**	**Condition**	**Estimated Cost**
	Johnson Street	5.5	2015	Average	$63,840
	M32 North	5.9	2016	Average	$47,200
	M32 East	2.8	2016	Good	$19,600
	Long Rapids Road West	18.2	2018	Average	$218,400
	Long Rapids Road East	7.2	2018	Average	$72,000
	Werth Road	12.9	2018	Average	$135,450
	Hamilton Road	9.9	2016	Good	$99,000
	Squaw Bay	15.5	2019	Average	$170,500
	Hobbs Drive	5.1	2019	Average	$51,000
	34.5 KV	10		Average	$50,000
Totals		93			$926,990

Year 2028	**Circuit**	**Miles**	**Last Year Trimmed**	**Condition**	**Estimated Cost**
	Fletcher St	4.9	2019	Average	$55,000
	Hubbard Lake North	47.5	2018	Average	$475,000
	Progress Street	17.6	2020	Good	$176,000
	Mall	4.6	2019	Good	$27,600
	Commercial	6.1	2019	Good	$48,800
	Ossineke	49.4	2021	Good	$345,800
	34.5 KV	10		Average	$50,000
Totals		140.1			$1,178,200

Table 5: Vegetation Management 5-Year Plan

6.1.2. Forestry Equipment

Using forestry equipment in vegetation management boosts efficiency, safety, precision, and sustainability, while reducing environmental impact and long-term cost. APC contractors use the following specialty equipment in everyday operations.

- All-Terrian Tree Trimmer: These trimmers can navigate rough and uneven terrain, making them ideal for difficult to reach areas. As well as provide precise cuts, which is crucial for maintaining clearances near power lines. They can handle a variety of vegetation types, from small branches to larger limbs, making them versatile for different environments.

- Mechanical Forestry Mulcher: These machines offer several benefits for vegetation management. Mulchers can quickly clear large areas of thick vegetation, reducing the time and labor needed. By combining clearing and mulching in one step they reduce overall costs for APC. Mulchers also offer sustainability by promoting healthier ecosystems by returning organic material to the soil.

- Excavator Mower: An attachment designed to be fitted on an excavator, enabling it to handle heavy duty vegetation management tasks. Its most useful benefit for APC contactors is the reach It allows. By having the ability to reach high or difficult-to-access areas, such as steep slopes or around obstacles. This helps to reach over ditches and to ensure APC contactors can maintain efficiency while clearing around rocky terrain.

There are many advantages to having a clean right of way for energized power lines. Outage durations are shorter because crews can more easily access damaged lines or poles. Better access to the lines also means better maintenance because crews can physically see the structures well and inspect for damaged parts or heat issues. Clear right of way is a safer work environment for everyone that needs to go near energized power lines including communications workers, utility workers, tree trimmers, and the public.

6.1.3. Vegetation Management Costs

APC contracts with a tree service for all its planned vegetation management and tree trimming activities. Contracts are competitively bid out. The following table outlines the tree trimming costs APC has incurred since 2018, as well as the forecasted amount through 2028.

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
TRANSMISSION TREE TRIMMING	$37,481	$293	$5,260	$16,282	$1,221	$50,000	$50,000	$50,000	$50,000	$50,000
DISTRIBUTION TREE TRIMMING	$283,466	$317,964	$581,743	$640,405	$620,545	$725,600	$884,600	$851,700	$877,000	$1,128,200
TOTAL TREE TRIMMING	$320,947	$318,257	$587,003	$656,687	$621,766	$775,600	$934,600	$901,700	$927,000	$1,178,200

Table 6: Vegetation Management Historical and Forecast Costs

As is shown in the table, since 2019, tree trimming costs have risen considerably. APC spent $320,947 in 2019, compared to $621,766 in 2023. Over those five years, the average yearly spend was $500,932. Costs rose sharply from 2020 to 2021, mainly because of the full commitment to ground to sky right of way clearing. Cutting the right of ways in this manner involves many tree removals which takes more time than just trimming them away from the lines. Therefore, it takes more crews to cut the same amount of miles which then increases the cost. That said, clearing the right of way ground to sky is the only way to accomplish a successful 5-year trimming cycle. APC is projected to spend an average of $943,420 per year for the next 5 years, with the forecasted trimming spend for 2028 to be over $1.1 million.

6.2. Substation Maintenance Program

APC utilizes the American National Standards Institute (ANSI) and the International Electrical Testing Association (NETA) maintenance testing specifications for electrical components as a guide for testing, as well as manufactures procedures listed in the equipment manuals. A visual inspection of all subtransmission substations is conducted once a week by APC Substation Technicians. This includes documentation of gauges, counters, locks, infrared scans of equipment, connections and more. At distribution substations APC Substation Technicians complete these checks once a month. Furthermore, Supervisors visually inspect the substations once a month. This places a visual inspection of distribution substations once every two weeks approximately.

Samples of all oil filled equipment are taken once a year and sent to a lab for testing. This testing allows APC to gain insight into the future life of the equipment as well as planning for needs in the future.

APC's goal is to test all substations on a rotating six-year basis. Customer specific substation can be difficult to schedule as it typically involves shutdown of the customer facility and APC works with its customers to balance the needs of the customer and providing adequate maintenance. All tests are conducted under a coordinated shutdown of the substation and include mechanical, electrical, calibration, etc. All testing is cataloged and trended to establish a baseline and check for equipment degradation over equipment lifetime. Testing frequency is listed in the following tables.

Substation Maintenance Inspection and Tests Target Frequency in Months Subtransmission Substation Equipment				
Equipment Type	Visual & IR	Oil Testing	Mechanical & Electrical	Internal Inspection
Liquid Filled Transformer	1/4	12	72	As Needed
Load Tap Changer	1/4	12	72	144
Circuit Breaker – Oil	1/4	12	72	144
Circuit Breaker – Vacuum	1/4	N/A	72	72
Circuit Breaker – SF6	1/4	N/A	72	72
Circuit Switcher	1/4	N/A	72	72
Relays – Solid State	1/4	N/A	72	N/A
Relays – Microprocessor	1/4	N/A	72	N/A
Instrument Transformers	1/4	N/A	72	N/A
SCADA	1/4	N/A	72	N/A
Substation Ground System	1/4	N/A	72	N/A
Substation Battery System	1/4	N/A	4	72
Surge Protection Devices	1/4	N/A	72	N/A
Disconnects/Switches	1/4	N/A	72	N/A

Table 7: Subtransmission Substation Maintenance Frequency Matrix

Substation Maintenance Inspection and Tests Target Frequency in Months Distribution Substation Equipment				
Equipment Type	Visual & IR	Oil Testing	Mechanical & Electrical	Internal Inspection
Liquid Filled Transformer	1	12	72	As Needed
Load Tap Changer	1	12	72	144
Voltage Regulators	1	12	72	As Needed
Instrument Transformers	1	N/A	72	N/A
SCADA	1	N/A	72	N/A
Substation Ground System	1	N/A	72	N/A
Surge Protection Devices	1	N/A	72	N/A
Circuit Reclosers	1	12	72	As Needed
Recloser Controller	1	N/A	72	As Needed
Disconnects/Switches	1	N/A	72	N/A

Table 8: Distribution Substation Maintenance Frequency Matrix

6.3. Pole Testing Program

On an annual basis, typically in the fall, Alpena contracts a pole testing company to target about 1,500 poles, which equates to a 14-year testing cycle. All wood poles including, subtransmission, three-phase distribution, single-phase distribution, secondary, and lighting poles are included in the program. Testing includes a visual inspection followed by a sonic test. If the sonic test is not conclusive, physical boring, probing and evaluating is completed.

The failure rate of our testing has historically been less than 10% with many years resulting in less than 5%. The failure rate averages 6% over the last 5 years of that 2% classified as rush and 4 % as condemned. The reasons for failure are even in percentages between heart rot, shell rot, and insect damage resulting in a heart rot condition.

After testing is completed, and over the next year, APC personnel replace failed poles prioritized by level of deterioration, importance, and accessibility. The following table illustrates APC's 5-year historical pole testing costs, as well as its 5-year forecasted pole testing costs.

	Historical Spend					Projected Spend				
Maintenance Account	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
POLE TESTING	$11,422	$15,656	$12,636	$14,703	$15,366	16,134	$16,941	$17,788	$18,677	$19,611

Table 9: Pole Testing Program Historical and Forecast Costs

6.4. Line Regulators and Reclosers

APC tests all the line regulators and reclosers on a rotating six-year cycle. American National Standards Institute (ANSI) and the International Electrical Testing Association (NETA) maintenance testing specifications as well as all manufacture procedures are implemented in APC's maintenance program.

Coordination with the Line Department at APC is completed to remove the equipment from the field. Equipment is then brought back to headquarters for testing and maintenance. APC has spares of all equipment to allow replacement in the field for maintenance. Testing includes visual, mechanical and electrical. Insultation testing, oil testing and other tests are conducted. This testing allows APC to gain insight into the future life of the equipment as well as planning for needs in the future.

6.5. Infrared Scanning

Infrared (IR) scanning is utilized by APC within its substations as an additional means of inspection and preventative maintenance. IR detects elevated levels of heat from loose connections, failing equipment, overloading conditions, and more. This first-level inspection tool allows APC to identify any potential issues before a major failure occurs. Most of time, APC's IR scanning inspections find problems at very early stages, allowing personnel to plan for an outage to correct the issue at the appropriate time.

Every week a substation technician visits all APC subtransmission substations to document indicators, do a visual inspection of the sub, and conduct an IR scan. Every month the distribution substations are inspected as well following the same inspection procedure. APC substation technicians use the IR camera to look at all the connection points, bus work, transformers, breakers, and all other equipment in the substation. They document and take pictures with an IR camera and return those findings to the Engineering Department. The Engineering Department then assesses the issue and monitors the problem or coordinates to have the equipment removed from service so repairs can be made.

6.6. Storm Response

APC is organized with enough Line Workers and Substation Technicians to be able to respond to almost all storms on the system, large or small, in an expedient manner. The weather is unpredictable, and APC has seen years of multiple catastrophic storms, years of zero catastrophic storms, and years of one or two catastrophic storms with several windstorms that nearly made it to the catastrophic level but fell just short. APC always has a Line Supervisor and a Line Worker on call, 24 hours a day. During off hour times when a storm suddenly pops up and hits, the on-call line worker gets the first call. Once they determine that it is a storm and there are multiple outages that need to be addressed, the line supervisor is notified and together they decide how many crews are needed. APC's entire system is monitored and controlled by SCADA. There are 5 total line supervisors, and well as the President and Vice President that have SCADA alarm notification. During a storm situation, many SCADA alarms usually come through, prompting the other supervisors to head into the main office for further instruction from the Supervisor on-call. APC utilizes the Milsoft Dispatch system to take the outage calls and predict the nearest upstream device that is open. Supervision uses this information to get a handle on where the outages are grouped, then dispatches crews accordingly.

If a major storm is forecasted ahead of time, APC supervisors and Line Workers spend time stocking and fueling trucks, fueling and sharpening saws, charging batteries etc. Every bit of preparation that can be done to speed up power restoration and make sure personnel are safe at all times is done. When the storm is over and all outages are restored, APC personnel go back through and restock the trucks and get everything back to proper working order for the next construction job.

If the storm appears that it will be a multi-day event, APC tries to organize the crews such that they all come in at daylight, then work 16 hours in as much daylight as possible before going home on rest. Typically, there will be one crew that crosses over the time when everyone else is on rest to handle the emergency calls. APC looks at every minute during a storm as critical to its customers and so every possible efficiency is put in place.

APC strives to be efficient with the dollars it spends related to storms, as it is a large variable maintenance cost for the company. Between the labor, transportation, and material costs that are incurred during a multi-day storm event, a year with any number of storms can have a large impact on the maintenance budget. As noted earlier, APC is only able to employ enough Line and Substation personnel to restore power expeditiously during storm situations because it does most its capital construction with internal labor. The only regular work subcontracted is the installation of underground pipe and wire. Therefore, APC's capital budget is somewhat fluid because storms are a maintenance expense that must be covered. In a year with many large storms, APC must cut back on the capital work it is doing because the maintenance costs must balance with the capital construction costs. APC is a relatively small utility, so the ability to be nimble is a bit easier, but capital planning is constantly being evaluated as events happen on the system.

6.7. Maintenance Costs

The following table shows the 5-year historical maintenance costs for APC, as well as the 5-year forecasted maintenance costs. As the table shows, APC breaks its maintenance costs down by Transmission (sub, line, and tree trimming), Distribution (broken out by substation, line and tree trimming, line transformers, meter maintenance, and miscellaneous distribution expense), and General (broken down by general plant, software maintenance, and main building maintenance). These costs include labor, equipment, miscellaneous materials, and other costs.

	Historical Spend					Projected Spend				
Maintenance Account	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
TRANSMISSION										
MAINTENANCE OF TRANSMISSION (sub,trees, and line)	$74,166	$16,607	$54,886	$71,072	$50,160	91,800	$96,600	$99,000	$101,400	$103,900
TOTAL TRANSMISSION	$74,166	$16,607	$54,886	$71,072	$50,160	91,800	$96,600	$99,000	$101,400	$103,900
DISTRIBUTION										
MAINTENANCE OF STRUCTURES (substation)	$76,324	$58,034	$33,716	$50,201	$131,277	$187,000	$195,600	$201,400	$207,400	$213,600
MAINTENANCE OF LINES (lines, tree trimming)	$528,226	$770,896	$1,042,987	$1,126,813	$959,854	$1,259,800	$1,441,300	$1,425,000	$1,467,500	$1,736,400
LINE TRANSFORMERS	$28,218	$24,732	$20,670	$37,999	$222,352	$106,100	$111,800	$114,900	$118,000	$121,400
MAINTENANCE OF METERS	$1,064	$114	$0	$2,185	$0	$0	$0	$0	$0	$0
MISCELLANEOUS DISTRIBUTION EXPENSE	$5,076	$3,075	$5,305	$6,111	$4,845	$6,700	$7,100	$7,300	$7,500	$7,700
TOTAL DISTRIBUTION	$638,909	$856,851	$1,102,678	$1,223,309	$1,318,328	$1,559,600	$1,755,800	$1,748,600	$1,800,400	$2,079,100
GENERAL										
MAINTENANCE OF GENERAL PLANT	$150,294	$107,024	$109,244	$118,846	$115,545	$93,000	$97,400	$100,300	$103,200	$106,100
MAINTENANCE OF SOFTWARE/EQUIPMENT	$87,980	$115,171	$109,621	$161,380	$209,183	$222,800	$233,100	$240,000	$247,200	$254,500
MAINTENANCE OF BUILDING	$164,587	$26,541	$51,820	$42,467	$32,118	$43,800	$45,800	$47,100	$48,400	$49,700
TOTAL GENERAL	$402,861	$248,737	$270,686	$322,693	$356,846	$359,600	$376,300	$387,400	$398,800	$410,300
POLE TESTING	$11,422	$15,656	$12,636	$14,703	$15,366	16,134	$16,941	$17,788	$18,677	$19,611
TOTAL MAINTENANCE EXPENSE	$1,127,358	$1,137,851	$1,440,886	$1,631,777	$1,740,700	$2,027,134	$2,245,641	$2,252,788	$2,319,277	$2,612,911

Table 10: Maintenance Program Historical and Forecast Costs

7. Capital Improvement Plan

APC employs nine Line workers, two Substation Technicians, and one Meter Worker. That group carries out nearly all capital construction except earth work, foundations, and specialized processes. APC employees build and rebuild subtransmission lines up to 138 kV, substations, line extensions, etc. and perform most test and maintenance activities.

APC has a relatively small distribution system footprint, especially when compared to other investor-owned utilities and cooperatives in the area. Facilities exist in four different counties and cover approximately 250 square miles. In some respects, APC's size makes capital planning easier than larger utilities because most of the system can be seen from a pickup, allowing supervisors and lineman to visually inspect the system frequently, even as they head to other jobs. Larger projects are easier to plan because the time required to meet on site is not significant.

The Mission Statement of Alpena Power is as follows:

"The mission of Alpena Power Company is to provide in a responsible and environmentally compatible manner: for our customers, hi quality, low-cost utility services; for our employees, continuing development in a productive workplace; and for our shareholders, a fair rate of return on their investment."

This mission statement is taken under consideration in every decision that is made at APC. It has always been a top priority of Alpena Power to provide the most reliable electric service at the lowest possible cost. We have taken great care to organize our capital improvement activities to support that philosophy. Over the past seven years APC has spent approximately 26 million dollars on capital construction projects, an average of just under 4 million per year. That is a significant amount considering we have 32 employees and roughly 16,700 customers. Coming out of the COVID pandemic, inflationary pressure on materials utilized in utility construction have severely impacted APC and its ability to take on projects. APC is essentially doing the same amount of capital work, but the capital cash outlay has increased from approximately 2.9 million dollars in 2019 to approximately 5.6 million dollars in 2023. The cost of APC's Capital program has nearly doubled while the work has essentially remained the same. APC is forecasting to spend approximately over 28 million dollars over the next 5 years of its capital plan.

Year after year, APC has been one of the best utilities in the state in reliability metrics as shown in Section 3.3. These results reflect the success of APC's capital replacement and construction strategy, driven by proper maintenance, pertinent and reliable testing data, long term planning, and financial commitment to the plan. APC's intention is to continue to utilize the same strategy for capital construction going forward.

7.1. Capital Project Screening Process

APC utilizes a rolling five-year capital budget that is updated annually. Capital projects are selected based on several factors that include, but are not necessarily limited to, a 20-year capital plan, testing and maintenance data, age and condition of assets, and service territory changes and needs. Once APC identifies capital projects that support reliability goals, a scoring matrix is utilized that evaluates safety risk, likelihood of failure, impact to the system and our customers, and how much reliability and resiliency improvement the project would provide. Once projects are prioritized using the scoring matrix, APC personnel evaluate the cost of each project, permitting requirements, equipment needed for purchase and the associated lead times, and any other pertinent aspects of the project that have timing concerns. Projects are then planned and budgeted for the appropriate construction season.

7.1.1. Capital Project Selection Analysis and Procedure

APC employs five on-call line supervisors that also are responsible for various aspects of the utility. APC supervisors oversee inventory, fleet management, safety, tree trimming, substation maintenance, metering, line construction and maintenance, building maintenance, and management of the engineering department. All the work that happens on the distribution system flows through the five supervisors, then to the line workers and substation and metering technicians.

Due to APC's small employee count and relatively small footprint, engineering and operations personnel have a very strong understanding of the state of the system. Historically, the five operations and engineering line supervisors, along with the vice president of operations, the president, and the IT/IS director have met monthly to discuss departmental updates, budget review, and capital construction planning. With APC's compact distribution and transmission footprint, effective capital planning has always been effectively done by participants in these monthly meeting proposing projects, justifying the return versus the cost, and the priority of one project over another.

In 2023, APC operations and engineering line supervisors developed a tool for scoring and ranking the projects contained within the twenty-year capital construction plan. A sample of the matrix is shown below. Scoring categories chosen were safety, likelihood of failure, customer impact, increase in reliability, and increase in resiliency. APC decided not to weigh any of the categories any higher than another. Over several lengthy planning sessions, all the projects in the twenty-year plan were scored, then sorted in the matrix based on highest risk to lowest risk. Projects were then evaluated on variables such as cost of the project, competing projects, lead time of materials, permitting issues, make ready infrastructure requirements, etc. A sample of the scoring matrix is shown below.

SUBSTATION / AREA	Circuit	Year Sub Built	**Project Rating Scale (None-1, Slight-2, Moderate-3, Substantial-4, High-5)** Project	2024-2028	**Safety Risk**	**Likelihood of Failure**	**Customer Impact**	**Increase in Reliability**	**Increase in Resiliancy**	**Total Risk Score**
Central	Business		Engineering for new circuit and existing downtown cleanup	$125,000	3	3	3	3	5	17
Rockport	Grand Lake	1980	Construct Grant project for UG at Maple, FLISR, and Rayburn Tie	$400,000	2	3	4	4	4	17
Transmission	34.5kV		Rebuild 4Mile 388 to Potter field, double circuit 138kV	$500,000	2	4	1	4	5	16
Northeast	Bloom Rd	1955	Rebuild Bloom Rd, 3ph NE Sub to N Point Rd	160,000	4	3	2	2	4	15
South	Werth Rd	1957	Rebuild Werth Rd Circ from Sub to Indian Reserve Rd(5.7 mi)	$500,000	3	3	3	4	2	15
General Substation Projects			Replace existing VWE Reclosers, upgrade controllers in substations	$300,000	3	3	4	4	1	15
Central			Install new spare 10MVA, Replace all Reclosers and add new exit for	$230,000	2	3	3	4	3	15
Transmission	34.5kV		Re-Insulate NE SW Jnc to Rockport-add OPGW-4.5 miles	$485,000	2	2	5	2	3	14
Progress St	Progress St	1994	New Voltage Regs and Controllers in Sub and Ball Field	$250,000	2	3	4	4	1	14
Ontario		1966	Construct new Circuit to break up 10th St	$205,000	1	2	4	3	4	14
Southwest		1954	Replace 3.75MVA transformer w/reman	$450,000	1	3	4	4	2	14
Bagley	Long Rapids Rd		Reconductor underbuilt from Johnson St to PF		1	2	3	2	5	13
Hubbard Lake		1976	Rebuild Hubbard Lake Junction (199,299, ABS)		3	2	2	3	3	13
Northside	Johnson St	1968	Rebuild 3-Phase (in conjunction with 4-Mile 288)		3	3	3	3	1	13
Norway		1978	Install second substation circuit(or feed from M-32) across the river		1	1	4	4	3	13
Ontario		1966	Replace XFMR (1996 reman)		2	3	4	3	1	13
Ontario	High School	1966	Reconductor from Christian out to Ontario St.		1	2	2	4	4	13
Progress St	Progress St	1994	Install FLISR		1	3	3	2	4	13
South		1957	Replace Sub XFMR		1	3	4	4	1	13
Transmission	34.5kV		Rebuild 34.5 kv PF# 188 line, 3rd street to South Sub		2	2	4	3	1	12
Bagley	Long Rapids Rd		Reconductor Genschaw Rd, Golf Course Rd and US-23 N tie line		1	2	3	2	4	12
Northeast	Hamilton Rd	1955	Rebuild tie line from sub to ABS on Hamilton Rd (2.4 miles) (tie in with rebuild of 34.5kV, roll the 266 down)		2	2	2	2	4	12
Ossineke	Squaw Bay	1964	Reconductor line from Timm Dr to Squaw Bay as 1 phase(3.5 mi.)		2	2	3	2	3	12
Rockport	Grand Lake	1980	Reconductor 3 phase line from Sub to US-23 N (1.1 miles)		1	2	3	2	4	12
South	Hobbs Dr	1957	Rebuild line from Sub to 3rd St ABS(1.5 miles)		2	2	4	3	1	12
North Industrial Park	Park-West	1999	Reconductor from Sub to Hamilton Rd ABS (1 mile)		1	1	2	2	5	11
Potter Field		1986	Install 2nd 24/32/40 Mva transformer		1	2	2	2	4	11
Progress St	Progress St	1994	Add 2nd circuit from sub down ITC ROW to First, then across river		1	2	2	2	4	11
Rockport	Grand Lake	1980	Replace Sub XFMR		1	2	3	4	1	11

Table 11: Capital Project Scoring Tool

7.1.2. Environmental Justice

Alpena service territory includes 16 census tracts and are scored by the EGLE MiEJScreen as shown in the following table:

Census Tract Number	County	Environmental Conditions Percentile	Population Characteristics Percentile	MiEJ Score Percentile
26141950600	Presque Isle	1	6	1
26141950500	Presque Isle	3	25	3
26119910300	Montmorency	5	48	10
26119910100	Montmorency	2	55	7
26007000900	Alpena	9	37	11
26007000800	Alpena	13	47	20
26007000700	Alpena	10	57	19
26007000600	Alpena	6	59	14
26007000500	Alpena	13	54	22
26007000400	Alpena	19	68	39
26007000300	Alpena	15	53	27
26007000200	Alpena	7	42	11
26007000102	Alpena	8	39	10
26007000101	Alpena	8	39	10
26001970500	Alcona	1	65	5
26001000100	Alcona	0	29	1

Table 12: Alpena Service Territory MiEJ Score by Census Tract

The MiEJ scores range from 1 to 39 throughout the service territory, when looking at the circuits located within the census tracts and their reliability, it shows that the census tracts with the best MiEJ Scores in fact have some of the worst reliability on the system while the Census tracts with worse MiEJ Scores have better reliability. This is due to the census tracts with higher MiEJ scores being in the urban portion of the service territory which typically has better reliability compared to the lower MiEJ scored census tracts being in the rural portion of the service territory. For comparison, Alpena 2023 SAIDI all weather is 37 minutes, while the 5-year average is 150 minutes. The three lowest and three highest scored census tracts, the circuits in serving the tract, and circuit reliability on a circuit bases are shown in the following two tables.

Census Tract Number	MiEJ Score Percentile	Circuit Number	2023 SAIDI All Weather	5-year average SAIDI All Weather
26141950600	1	22	73.5	444.1
26141950500	3	14	53.1	173.2
26141950500	3	22	73.5	444.1
26001000100	1	8	29.4	254.5
26001000100	1	20	76.7	333.8
26001000100	1	39	289.3	534.2

Table 13: Top 3 MiEJ Scored Census Tracts and Reliability Data

Census Tract Number	MiEJ Score Percentile	Circuit Number	2023 SAIDI All Weather	5-year average SAIDI All Weather
26007000500	22	2	0.1	0.9
26007000500	22	3	7.4	113.1
26007000500	22	5	4.6	18.6
26007000500	22	9	0.3	79.4
26007000500	22	43	35.3	31.4
26007000400	39	2	0.1	0.9
26007000400	39	3	7.4	113.1
26007000400	39	4	22.5	88.1
26007000400	39	5	4.6	18.6
26007000400	39	15	0.6	37.8
26007000400	39	16	33.9	122.4
26007000400	39	19	14.1	95.0
26007000300	27	10	8.9	49.2
26007000300	27	11	104.6	480.2
26007000300	27	12	33.9	177.7
26007000300	27	13	2.7	35.5
26007000300	27	14	53.1	173.2
26007000300	27	15	0.6	37.8
26007000300	27	16	33.9	122.4
26007000300	27	22	73.5	444.1
26007000300	27	38	46.8	133.8
26007000300	27	45	10.7	10.7

Table 14: Lowest 3 MiEJ Scored Census Tracts and Reliability Data

7.1.3. Major Event Risk

Major event risk pertains to the risk of large-scale outages on the system, such as the loss of a substation or subtransmission feed to of the system. These events can be caused by weather, wildlife, vegetation, equipment failure, etc. and can have a significant impact on many customers.

APC has spent years designing and building redundancies into the subtransmission and distribution system that it currently operates. With these redundancies, the operations team can move load around the system easily, allowing for regular maintenance of substation equipment as well as shorter duration outages if major events happen on the system.

APC currently has three separate 138 kV feeds into the main point of interconnection at the Four-Mile subtransmission substation, with a fourth being added in Q4 2024 as part of METC's new Long Rapids Substation being built near the current site. The other two 138 kV subtransmission substations on the system, Potter Field Sub and Gennrich Sub are fed from Four-Mile Sub and have multiple lines connecting them to Four-Mile. Future resiliency capital plans for Four Mile substation involve the construction of a new 138kV switch yard that attaches to METC's Long Rapids Substation. This switchyard will be built as a breaker and a half scheme, giving each exit a backup, and allowing APC to move subtransmission load when necessary. This design also allows each piece of equipment to be easily shut down for maintenance. Currently, the site is being cleared, with earthwork and foundations scheduled to start in 2027.

Potter Field and Gennrich Subs have the capacity, both in transformer and circuits, to support the full load of APC's distribution system.

APC has another point of 138 kV interconnection at the Progress St Substation in Hillman, Michigan. That substation transformer is a 138 kV to 13.2 kV that has only one feed into it, but it also only has one circuit that it feeds and there exists a backup for it from another distribution circuit. There are a few smaller manufacturing businesses that can't operate if the alternate feed is in operation because of the voltage flicker, but all of the residential load can be carried.

APC's 34.5 kV sub transmission system was designed with an eye towards redundancy and flexibility to move load around the system. Therefore, an event that causes a total loss of one or more portions of the 34.5 kV sub transmission systems can be managed by transferring loads to adjoining substations, either using the 34.5 kV system, or if necessary, at the 13.2 kV distribution level.

Similarly, the 13.2 kV distribution system has redundancy like the 34.5 kV system. The loads of all the substations have alternate sources of energy, and these loads can be easily moved between the available sources. A return to service of loads lost after a complete loss of a substation can be managed in a relatively short period of time.

Within APC's Capital Improvement Plan and budget, a priority is put on projects that increase reliability and resiliency within the system, which is why the scoring matrix exists to quantify the actual impact to the system. The more redundancy that exists in the system, the more capable APC is to respond efficiently during major events on the system. The following are some specific examples of projects APC has completed or has planned that address resiliency and major event risk preparedness:

- In 2023, a new circuit was built out of the Bagley St Sub that cut a circuit of approximately 1,300 customers into two smaller circuits of approximately 600 and 700 customers each and provided another option to shft load around that substation.
- In 2024, a new circuit will be built out of the Ontario St Substation that will cut a circuit of approximately 1,200 customers into two smaller circuits, and again adding flexibility to shift load.
- In 2027, a new breaker exit configuration at Gennrich Sub will be built that will allow that sub transmission circuit to be utilized by more substations on the system, further increasing APC's resiliency.

7.1.4. Poor Performing Circuits

APC has 34 circuits, not including dedicated customer circuits or backup circuits, that make up its distribution system that serves customers in an area of roughly 250 square miles. The service territory ranges across four counties and is a mix of rural and urban areas. Each year, APC submits reliability and power quality data to the State, but the Engineering department also builds an Annual Outage Report for the company that looks at the outage data from many different aspects.

Outage minute data is evaluated including and excluding major events, by substation and feeder, and by cause. New to the report for the State in 2024, outage data is also evaluated by census tract and zip code. APC also analyzes the reliability indices by substation and feeder to compare the results to year over year averages. This allows APC Engineering and Operations to evaluate any trends that need to be addressed as well as identify poor performing circuits and/or feeders. An analysis of the worst performing circuits, both by total outage minutes as well as by SAIFI, SAIDI, and CAIDI, then provides the foundation for a plan for circuit reliability improvement. Issues can include vegetation management, maintenance, or capital improvement projects that need to be undertaken to improve circuit reliability. The report provides the data, the APC team analyzes the results to ensure complete understanding of the actual root cause of the reliability issues, then evaluates the options and chooses a path to address the identified issues.

Over the past five years, APC's worst overall performing circuits, both by minutes and reliability metrics, have been South Shore Circuit, Hubbard Lake South Circuit, and Grand Lake Circuit. There have been other circuits that have appeared on the list, but they were affected by one off events, such as a fire, windstorms that didn't quite become a catastrophic event, etc.

South Shore Circuit is a circuit located in the transition between urban and rural areas with some relatively significant tree presence near the three-phase. Vegetation was the major contributor to outage minutes and once a cycle trim was completed the circuit's reliability significantly improved.

Hubbard Lake South is a very large, rural circuit with heavy forest impact. It was due for a vegetation management cycle that was completed in 2022-2023. Along with the circuit trimming, two 3-phase reclosers were installed on the circuit to segment it. By installing these two devices on the three-phase, APC was able to reduce the number of customers impacted by an issue elsewhere on the circuit. After completing those two tasks, Hubbard Lake South circuit reliability has improved.

The Grand Lake Circuit is a long radial circuit on the very north end of APC's system that has heavy forest impact. It currently is APC's worst performing circuit both by SAIDI and SAIFI. APC has capital projects planned and budgeted in 2024 and 2025 for this circuit to convert .5 miles of overhead three phase wire to underground, as well as install a FLISR system to reduce the number of customers affected by outages down the line. Future projects are being evaluated for installation of tree cable in some areas, as well as the possibility of a second circuit to break up the 1,126 customers served by the circuit.

7.2. System Equipment Replacement

APC utilizes system equipment to receive energy to the system, safely operate and manage the system with proper voltage, power quality, fault response and isolation, and ultimately deliver reliable electric service to customers. Equipment types range from substation transformers, circuit breakers, reclosers, and air-break switches, to poles, wire, voltage regulators, CTs and PTs, and SCADA meters. Every piece of equipment has a vital purpose and must be in good working order to ensure the system operates safely, efficiently, and reliably. APC utilizes a robust maintenance and testing strategy to ensure that critical equipment is tested and inspected at proper intervals to ensure maintenance or replacement can be performed without the system suffering a failure. Most items are looked at from both an age and condition-based perspective. Historical data has shown that at certain ages for certain equipment, testing begins to show degradation of the asset and replacement should be appropriately planned. All this data is carefully tracked and recorded and is utilized in planning capital replacement projects for items such as reclosers, controllers, SCADA meters, substation transformers, etc. The preferred strategy is that these items are then replaced at data driven intervals, so APC does not find itself with a very large capital outlay such as having to replace all reclosers on the system because they are all the same age.

The rolling five-year capital construction plan APC develops strives to keep a balance between subtransmission, distribution overhead, and distribution underground work. APC's current capital plan, both the rolling five-year and the long term 20-year, contains an appropriate mix of subtransmission rebuilds, overhead distribution improvements, substation upgrades, and distribution underground replacements and installations.

7.2.1. Subtransmission Overhead System Equipment

This equipment category covers the poles, wire, and line equipment that make up APC's 138 kV and 34.5 kV sub transmission system. In 2009, due to age and testing results, it was decided to begin rebuilding the subtransmission system. Using loading information from systems studies completed by outside consultants along with evaluating the age and condition of line sections, projects have been identified over the last fifteen years.

Typically, APC spends between $600,000 and $1,000,000 on subtransmission line rebuild projects each year. Since 2009, approximately 9.0 miles of 138 kV and 18 miles of 34.5 kV have been updated. The priority of the line rebuild projects is determined by the factors scored in the capital screening scoring matrix. The oldest lines APC has on the sub transmission system were installed in 1955. The average age of all segments on the sub transmission system is 33 years. The current project APC is building is an eight mile stretch of 34.5 kV line that connects South Sub to Ossineke Sub in the south part of the system. It was installed in 1961. Two miles per year are built, making this a four-year project start to finish. The wood pole, single 34.5 kV circuit is being upgraded to steel pole, double circuit construction, insulated to 138 kV for future growth. The work is done completely in-house, with the only exception being the engineering design work. Once this project is complete APC will have approximately 27 miles of sub transmission line that was built prior to 1975. APC plans to continue to rebuild approximately two miles of sub transmission line every year. The next project will be the Four Mile 388, built in 1955, which is scheduled to start in 2028 after the current project finishes.

This category also includes subtransmission station equipment replacement. In 2021, APC replaced a 40 MVA substation transformer at its Gennrich substation at a project cost $1,107,071. Starting in 2026 APC will begin a multi-year project to replace its 138 kV switchyard at Four Mile Sub and relocate it out of the floodplain where it currently resides.

This is the single point of 138 kV interconnection for APC's entire system excluding the village and township of Hillman, which have their own single 138 kV point of interconnection.   It was built in the 1950s and is at end of its useful life.

Over the past 5 years, APC has spent a little over $6,212,000 on subtransmission station and overhead system equipment replacement. APC plans to spend $5,955,000 over the next 5 years replacing components in this category, all projects based on priority as scored by the selection matrix.

7.2.2. Distribution System Equipment

This category covers all the equipment utilized to operate the 13.2 kV distribution system that delivers electricity to the customer. APC has 22 substations and 34 circuits that carry the distribution load. Capital planning for substation equipment such as substation transformers, reclosers, CTs and PTs, etc. is done based on maintenance and testing data collected as the substations are shut down on scheduled rotation. Age of the asset and condition are also a consideration, however historical data APC collects and stores shows that as the asset ages to a certain point, the testing correlates with the typical end of life of that particular asset. For example, APC has historically seen that a substation transformer typically has a 45–55-year usable life before testing shows significant degradation. Therefore, it is the strategy of APC to replace, or in some cases rebuild, substation transformers before they reach the 50-year-old mark. In 2024, a 3.75 MVA transformer was replaced at the Southwest Substation which was the last sub transformer on the system close to 50 years old.

APC tests approximately 1,500 out of its approximately 21,000 poles every year. This results in a 14-year cycle which historically has been shown to be appropriate. The testing includes a visual inspection followed by a sonic test. If the sonic test is not conclusive, physical evaluation is completed. Typically, entire circuits are tested in the same year so that tracking is easy and accurate. Also, pole testing is planned to the circuits that have recently been trimmed for vegetation. This increases efficiency not only for the testers, but also for APC personnel as they access condemned and rush poles to replace them.

The failure rate of APC pole testing has historically been less than 10% with many years resulting in less than 5% condemned and rush poles. Rush poles are classified as poles that need be changed out at the earliest possible opportunity. Condemned are poles that need to be replaced but they are not subject to imminent failure. Over the past 5 years, pole failure rates have averaged 2% rush and 4% condemned, for a total average of 6%. The reasons for failure are even in percentages between heart rot, shell rot and insect damage resulting in a heart rot condition. APC typically tests poles in the fall of the year, with all poles that failed inspection replaced by the end of the following construction season.

APC is always looking for opportunities to harden the distribution system, whether it is converting overhead to underground where appropriate, creating more loops for system resiliency, or replacing aging overhead wire. Each month, APC supervision and engineering meets to discuss a myriad of operations topics. One of which is the discussion of general line upgrades that are needed on the system. Mostly this involves identifying sections of the system that still run on smaller copper wire. Copper wire is usually smaller diameter and more susceptible to line down events than the larger aluminum wire that replaces it. APC utilizes these meetings to identify these areas of the system and develop smaller scale line projects to reconductor those sections. The wire being replaced has been fully depreciated and the upgrade makes those sections much more resilient to weather and storm events. APC has not seen significant growth in its territory over the past 5 years so reconductoring lines for growth has not been necessary.

In Q1 2024, APC finished installing the last of 5 new voltage regulators on the system, recommended by a system study conducted in 2019. In addition, a maintenance cycle was completed on the existing regulators on the system. APC plans to replace 3-5 of the oldest regulators on the system in the next 5 years, as well as standardize controllers as there exists a range of different types in use currently.

APC's historical and planned capital spend for replacement of distribution system equipment is discussed at the end of the following section, 7.2.3 Underground System Equipment, as the tables include both categories.

7.2.3. Underground System Equipment

APC has installed underground distribution cables since before 1980. Pre-1980, the record of cable installations was very inconsistent. With the integration of GIS at Alpena Power in the early 2000's, any underground cable without a known installation date was entered as January 1st, 1980. Within the current capital improvement strategy, APC has focused its yearly cable replacement projects to upgrade those pre-1980 cables. During a typical year, APC will complete 3-6 larger scale underground replacement projects which has kept unplanned failures of underground distribution wire to a minimum. APC employs a subcontractor to install underground conduit and wire which allows for 1-2 crews of contactors to be installing the underground assets while APC lineman build other projects. APC lineman then work with the contractors to do riser installation and final customer hookup. Over the past 4 years, APC has averaged well over 100 customer underground installations and conversions per construction season, in addition to the major underground projects. APC's capital replacement plan for the next 5 years is to continue to utilize 2 contracted underground crews and replace 3-6 larger scale installations based on age every year, as well as construct and replace normal distribution type underground projects as required.

In 2025 APC will expand its record keeping to track underground capital construction work orders separately so that it can differentiate between overhead work compared to underground work on the system. In 2024, new construction work orders were separated from existing equipment replacement work orders. Prior to 2024, all distribution work was tracked together. Therefore, the yearly capital construction spend on distribution system equipment, comprised of overhead work, underground work, lights, meters, and tools and shop equipment, was represented in one lump sum.

Over the past 5 years, APC had spent over $8,395,000 on Distribution system capital replacement and construction for an average of $1,679,000 per year. In the next 5 years, APC's capital plan is to spend $12,564,000 for an average of $2,512,800 per year. The main reason for the large increase in spending is the inflationary cost of the goods used in utility construction.

7.2.4. Substation Equipment

APC substation major equipment: power transformers, circuit breakers, reclosers, etc. have an average age of 19 years. In accordance with our maintenance and testing programs we continue to trend a evaluate equipment each year. Looking at a multitude of factors such as age, importance, replacement parts or whole units, pricing, lead times, safety, and reliability.

Each year APC evaluates the need of equipment for immediate replacement, five years out and even twenty years. This allows us to keep our average age of equipment down and replace necessary equipment as the full life has been used. Due to exceeding long lead times and price increases APC scrutinizes every piece of equipment that needs to be replaced and identifies the best course of action.

Over the past 5 years, APC has replaced substation transformers at four different substations. One more was replaced in 2024, a refurbished 3.75 MVA that replaced a unit from 1975. Other capital improvements have included replacing end of life substation reclosers with new reclosers, new SCADA metering, new PTs and CTs, and breaking up large circuits by building more circuits out of existing substations. At this point, APC's oldest substation transformer is 45 years old, with the next oldest coming in at 38 years old. APC has spent $2,414,900 on substation capital projects over the past five years. In the next five years, APC projects to spend $1,437,000 on distribution substation capital work, which includes the remanufactured substation transformer as well as a project to bring fiber into APC's Rockport sub towards the end of the period. APC must upgrade its main facilities, as well as start a major transmission switchyard project, so the spend over the next five years will be less in this category than the past five.

7.2.5. Line Transformers

Over the past 5 years, APC has spent $1,603,633 on line transformers. Up until approximately 2021, APC purchased brand new transformers with stainless steel cases and spent an average of about $120,000-$140,000 per year. Over the next 5 years, APC projects to spend $3,050,000, or an average of $610,000 per year on line transformers. The majority of these are not brand new, they are remanufactured with mild steel cases. New transformers cost double what a remanufactured unit costs, and remanufactured units are 200-400% more expensive today than they were 3-4 years ago. Lead times for new transformers are stretching into the three-year range with some manufacturers and delivery promises are seldom kept. APC believes a balance of new and remanufactured units is appropriate and that strategy is reflected in the projected 5-year capital spend for replacement of line transformers.

7.3. Technology and Automation

7.3.1. FLISR

Outage restoration times and minimizing the affected area of an outage are keys to improving performance. Automation, where possible, can be utilized to segment sections of line that have experienced a fault and utilize a second source to provide power to the segment that was downline of the faulted section. Automated systems such as this are called Fault Location, Isolation, and Service Restoration (FLISR). APC sees the opportunity for immediate improvements to outage size and duration by harnessing this type of automation on its feeders. In isolated parts of the system, such as the Village of Hillman or Grand Lake area, that take longer to get personnel and equipment to along with longer radial lines that could be configured with multiple feeds. This would allow the FLISR system to segment the outage to the smallest possible area, keeping outage minutes lower than if the entire circuit was off and improving the reliability of the overall system. APC has applied for a Department of Energy (DOE) Grant through the Michigan Department of Environment, Great Lakes, and Energy (EGLE) to install a test FLISR system that will create a looped section in a radial feeder in an effort to maintain the end of the line customers. This grant will allow APC to venture into automation much sooner than it would have without, as other projects would score higher on the priority list than investment in new technology.

7.3.2. AMI

APC continues to reinvest in its system for the benefit of the ratepayers. New and cutting-edge technology has not been part of the strategy at APC. Due to the size and historically low cost to the ratepayer, APC has been one to allow things to be tested and proved out by others in the industry before adopting them for its own use. A good example of this was the change to automated meter reading (AMR) that was implemented in 2014. A complete change of the 16,000 plus meters on the system was conducted when there was a lot of discussion in the industry concerning advanced metering infrastructure (AMI). APC chose to go in the direction of the simpler, less controversial AMR route at that time to save costs on reading meters. Ten years later, APC is now lagging as many utilities have piloted AMI programs and have or are beginning to implement them on the systems. AMI provides many customer benefits such as availability of more concise data as to their usage, avoidance of trip charges for non-outage events, etc. It also comes with utility benefits such as outage restoration verification, improved outage predictions, etc. There are also cybersecurity and data privacy concerns that also need to be addressed. APC recognizes the pros and cons of changing to an AMI system and is looking at ways to minimize the concerns of ratepayers and the overseers of the electric utilities. APC has identified that it would prefer to avoid any mesh network AMI to maintain that customer data is not bounced through other customers meters. Utilizing secure communication between existing company owned communication networks has also been identified as a priority. There is also the additional cost of replacing a system that is only ten years old. Historically, APC has gotten every last bit of life out of its equipment before replacement, but there has not been the longevity in the newer solid-state meters. They have proven to be accurate and reliable to the point that just no longer work. Failures have been occasional, but they do not seem to be as robust as the prior electro mechanicals they replaced. APC has planned to begin infrastructure investments in its 2029 budget for a possible roll out of meter replacements beginning in 2031.

7.4. Facilities and Vehicles

7.4.1. Facilities Plan

APC has one location where all employees work from. It started out as a garage/shop but has since seen two additions to get everyone under one roof. Unfortunately, approximately 6 years ago, it was discovered that the first addition, built in 1991, was not supported properly. The whole side of the building is settling, causing issues with walls, doors, floors, and plumbing.

APC contracted an engineering firm to evaluate the situation and provide guidance. Through soil borings and field assessments, they determined that the best course of action is to tear down the failing building and rebuild it in parts. For business continuity impact to the capital budget renovation must happen in phases. Therefore, the first phase of the reconstruction project will be to add on to the shop and move the existing shop and storeroom into that new addition. That opens up enough space to start phase two, which is to renovate that area into new offices for the people to be displaced when the settling building is torn down. Once the new shop is built and the offices are complete, those people will move in, and demolition can start on the section of the building that is failing. The demolition and reconstruction of that side of the building is phase three. It is anticipated that phase one will start in 2025, phase two in 2026, and phase 3 in 2027 and the total cost is estimated at $3,600,000.

7.4.2. Vehicle Plan

Alpena Power Company operates a fleet of eight bucket and digger derrick trucks, seventeen light duty vehicles, and many additional pieces of off road and specialized equipment. Reliable operation of this equipment is critical to operations, construction, and outage restoration. All vehicles are evaluated for useful life and replacements are included in the capital plan. Light duty trucks are rolled into other areas of the company as they gain miles or for other operational reasons to get the most life out of them as possible. Heavy duty trucks are evaluated based on hours, usage, and condition when determining replacement. APC's vehicle plan seeks to maximize value and life of an asset, while also ensuring the reliable operation of every piece of equipment used by personnel to keep power on for the customers.

7.5. Five Year Capital Improvement Plan Summary

SUB TRANSMISSION OVERHEAD SYSTEM EQUIPMENT	2024	2025	2026	2027	2028
Gennrich Sub	$0	$0	$0	$120,000	$0
Potterfield Sub	$0	$0	$0	$0	$20,000
4-Mile Sub	$0	$0	$10,000	$0	$0
Long Rapids Switchyard	$500,000	$0	$900,000	$900,000	$600,000
4-Mile 388 34.5 kV Rebuild	$0	$0	$0	$0	$900,000
South Sub to Ossineke 34.5kV Rebuild	$865,000	$800,000	$340,000	$0	$0
TOTAL	$1,365,000	$800,000	$1,250,000	$1,020,000	$1,520,000
LINE TRANSFORMERS					
Line Transformers	$625,000	$625,000	$650,000	$650,000	$500,000
TOTAL	$625,000	$625,000	$650,000	$650,000	$500,000
DISTRIBUTION SYSTEM EQUIPMENT					
UNDERGROUND SYSTEM EQUIPMENT					
Meters	$15,000	$50,000	$50,000	$50,000	$50,000
Blanket Work Orders	$2,173,000	$2,188,000	$2,570,000	$2,893,000	$2,355,000
Tools and Shop Equipment	$50,000	$30,000	$30,000	$30,000	$30,000
TOTAL	$2,238,000	$2,268,000	$2,650,000	$2,973,000	$2,435,000
FLISR					
Grand Lake Circuit Upgrades	$0	$122,000	$0	$0	$0
TOTAL	$0	$122,000	$0	$0	$0
FACILITIES					
Office Structure Improvements	$150,000	$1,200,000	$1,200,000	$1,200,000	$0
Computers & Related Equip/software	$90,000	$45,000	$45,000	$55,000	$55,000
TOTAL	$240,000	$1,245,000	$1,245,000	$1,255,000	$55,000
VEHICLES					
Power Operated/Transportation Equipment	$465,000	$255,000	$55,000	$55,000	$455,000
TOTAL	$465,000	$255,000	$55,000	$55,000	$455,000
SUBSTATION EQUIPMENT					
Hospital Sub	$0	$10,000	$0	$0	$0
Northeast Sub	$0	$0	$0	$10,000	$0
Hubbard Lake Sub	$0	$0	$10,000	$0	$0
M-32 Sub	$0	$0	$0	$0	$5,000
Northside Sub	$0	$0	$0	$5,000	$0
Bagley Sub	$0	$0	$0	$0	$5,000
Ontario Sub	$305,000	$0	$0	$0	$0
South Sub	$0	$10,000	$0	$0	$0
Northeast Sub	$0	$0	$0	$0	$40,000
Southwest Sub	$450,000	$0	$0	$0	$0
North Industrial Sub	$0	$0	$10,000	$0	$0
Central Sub	$110,000	$0	$0	$0	$10,000
ATI Sub	$0	$0	$0	$2,000	$0
Progress St	$0	$10,000	$0	$0	$0
Rockport	$0	$0	$0	$10,000	$435,000
TOTAL	$865,000	$30,000	$20,000	$27,000	$495,000
Total Capital	$5,798,000	$5,345,000	$5,870,000	$5,980,000	$5,460,000

Table 15: 5-Year Capital Improvement Plan Summary

8. Executing the Distribution Plan

APC will continue to be intentional and deliberate with the execution of the Distribution Plan. The service provided is essential to life for the customers of the utility, so the long-term viability of the company is a top priority. It will take the expertise of all APC employees to continue to plan, develop, and execute the projects required to continuously serve APC's customers with highly reliable, low-cost service. It is APC's plan to continue to do those things that have made the company successful and strive to improve in the areas of the business that produce efficiency and reliability in our system.

8.1. Operations and Engineering Organization

APC identifies, engineers, and executes most of its work. For large scale projects such as subtransmission line rebuilds or substation construction projects, an engineering consultant is contracted to complete the design work. An outside firm is subcontracted to install underground conduit and wire. All other work is performed by APC personnel.

APC's Operations and Engineering organization is set up to be as lean and efficient as possible. Everyone has multiple roles and can be a backup to many others. The Engineering department consists of the Customer Service Field Engineer, the Utility Engineering Technician, and the Systems Engineer/Repair Supervisor. They are managed by the Engineering Director, and both the Engineering Director and the Repair Supervisor are on-call supervisors. Two Substation Technicians and a Metering Technician report to the Repair Supervisor. Every bit of work that gets done comes through that department one way or another.

The Operations group consists of the Line Superintendent, Fleet/Inventory Supervisor, and the Vegetation Management Supervisor/Safety Director. These three supervisors are on-call supervisors and are all backups for each other in case of absence. There are nine Lineworkers that report to the Superintendent. APC lineworkers and substation technicians carry out a majority of the line and substation work contained in the Capital Construction plan. The Operations Department and the Engineering Director report to the Vice President-Operations and Engineering.

8.2. Workforce Planning

This workforce organization requires all its employees to be cross-trained and flexible over the course of a day. However, it delivers efficiency in work planning and execution, seamless coverage when employees are absent, and keeps costs to the rate payers as low as possible. Another aspect of workforce planning is having appropriate personnel available for storm situations. APC strives to be efficient with the dollars it spends related to storms, as it is a large variable maintenance cost for the company. As noted earlier, APC is able to employ enough Line and Substation personnel to restore power expeditiously during storm situations by doing a majority of its capital construction in house. Therefore, APC's capital budget is somewhat fluid since storms are a maintenance expense that must be covered. In a year with many large storms, APC will balance capital work with maintenance costs, so the entire budget remains in balance.

Alpena Power Company is a relatively small utility, so the ability to be nimble is a bit easier, but capital planning is constantly being evaluated and prioritized as events happen on the system. A large technology upgrade was recently implemented that is designed to make some of the labor-intensive data collecting and reporting much more efficient. Nothing in APC's forecast shows a need to plan for a greater workforce than the one currently employed.

8.3. Issues and Challenges

Inflation has been a significant issue across all goods, but electrical supply has been hit extremely hard. Transformer prices have increased over 400% in some cases from 2020. Most of the parts and pieces APC utilizes on a daily basis have increased in cost at a rate well above the inflationary rate. Additionally, delivery promises are rarely kept so inventory management at APC has been a top priority. The Inventory Supervisor orders far ahead of time, has upped the maximum quantities for high turn items, has looked for and located any and all alternates for parts that are expensive or have long lead times, and has utilized many different vendors. The shortage of material and the pricing pressures have been around for 3-4 years at this point, so the key to issues and challenges APC is facing is planning. APC operations is planning with far greater detail and much further ahead than it ever has before, and it yields success in that projects are happening as planned. APC will continue to get further ahead of projects, further expand the purchasing network, and continue to look for lower cost alternatives to everything it purchases.

8.4. Storm Response

8.4.1. Mutual Assistance

APC is a member of the Michigan Electric Cooperative Association (MECA) safety organization which provides safety training and mutual aid coordination. In the past thirty years, APC has provided mutual aid to Presque Isle Electric & Gas, Thumb Electric, Great Lakes Energy, Cloverland, Consumers Power, and the City of Sturgis. APC has not requested mutual aid from any other utility in the past several decades.

8.4.2. Wire Down Response

On occasion, a wire will get damaged and be laying on the ground. This is a dangerous situation and once someone is on scene and there is a wire down, they cannot leave until someone else gets there to either fix it or keep the scene safe. Typically, the notification call will come in from Emergency Services, whether it is police, fire, etc. and so they are the ones on scene until APC arrives. APC standard operating procedure is that whenever there is a wire down call, someone from Operations immediately heads to the location to relieve Emergency Service personnel so that they can get back to their own responsibilities. There is always a lineman and a supervisor on call and APC's service territory can typically be traversed end to end in less than 1.5 hours. This aids APC in being able to respond very quickly to a wire down call. Under normal conditions, it would not be uncommon to have Emergency Services relieved within 15-45 minutes. In storm events, the time might be slightly longer, but APC has trained office personnel to wire watch so the utility has many people who can go out and relieve Emergency Services and still make sure someone is keeping the scene safe where the wire is down. APC has been compliant with the standard set forth by the commission.

9. Conclusion and Financial Summary

For over 140 years, Alpena Power Company has consistently delivered reliable, cost-effective, and environmentally responsible service to the citizens and businesses of northeast lower Michigan. We have done so by listening to the needs of our customers and acting on those needs through proactive planning and execution of our maintenance and capital plans.

Historically Alpena has been one of the most reliable and cost-effective utilities in the state, but that does not mean the job is done. As shown in this Distribution Plan, challenges continue to arise including changing weather patterns and climate change, further electrification of transportation and buildings, significant additions to distributed generation and storage, supply chain issues and inflationary pressures. The employees of Alpena are ready to meet those challenges by proposing to invest $28.45 million in capital from 2024 to 2028 compared to $20.64 invested from 2019 to 2023 and spend $11.46 million in O&M from 2024 to 2028 compared to $7.08 million from 2019 to 2023.

Alpena believes that the investments and spending outlined in the Distribution Plan will allow us to continue to meet our mission to provide in a responsible and environmentally compatible manner: for our customers, hi quality, low-cost utility services; for our employees, continuing development in a productive workplace; and for our shareholders, a fair rate of return on their investment. Timely recovery of the costs of the investments and expenses is essential in allowing Alpena Power Company to continue delivering on its mission.

Alpena looks forward to working with the Commission, Staff, and stakeholders to continue to improve on and execute its Distribution Plan.