7 Maintaining Reliability and Investing in Resiliency

7.1 Introduction

Overall, VEC has seen a decline in both in duration and quantity of outages. Prior to 2009 large substation outages that were few in number had high member impacts affected much of VEC's system. After completing significant investment into these facilities, we are more focused downstream of these substations.

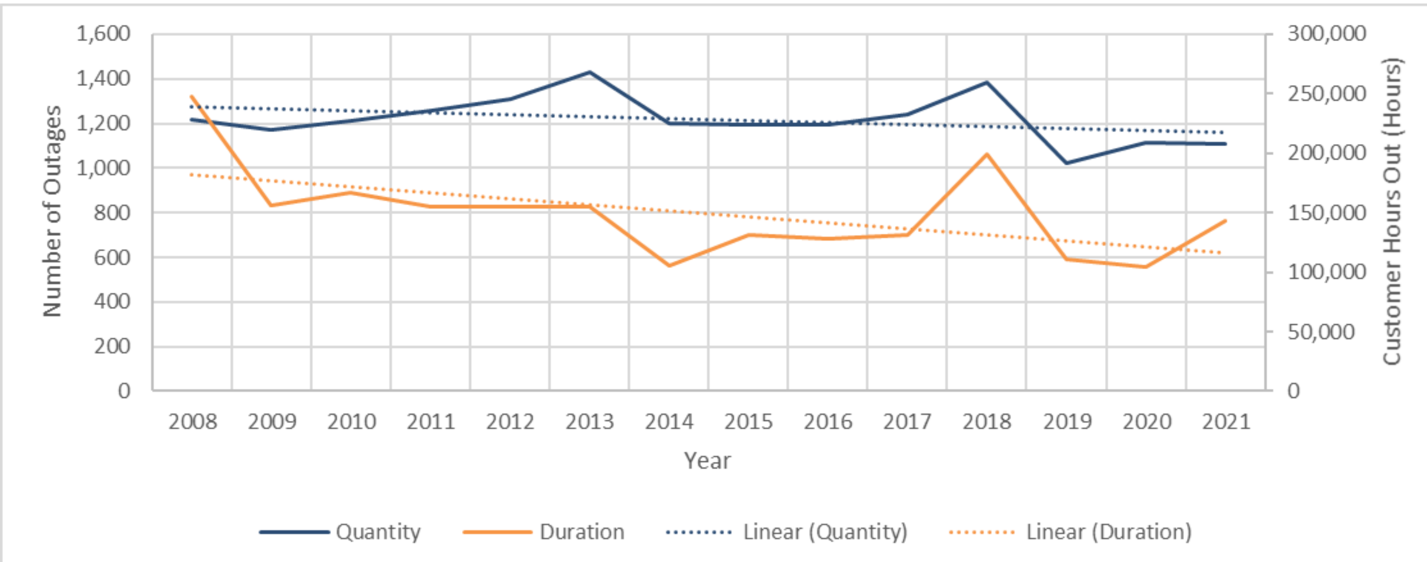


Figure 7.1.1.A VEC's outage quantity and duration 2008-2021

VEC continues to see increased outages due to more frequent weather events such as wind storms, wet snow or ice, and thunderstorms. Additionally, capacity constraints are increasing throughout the country and in the winter months for New England. VEC's priority remains to maintain reliability and balance investment in system resiliency.

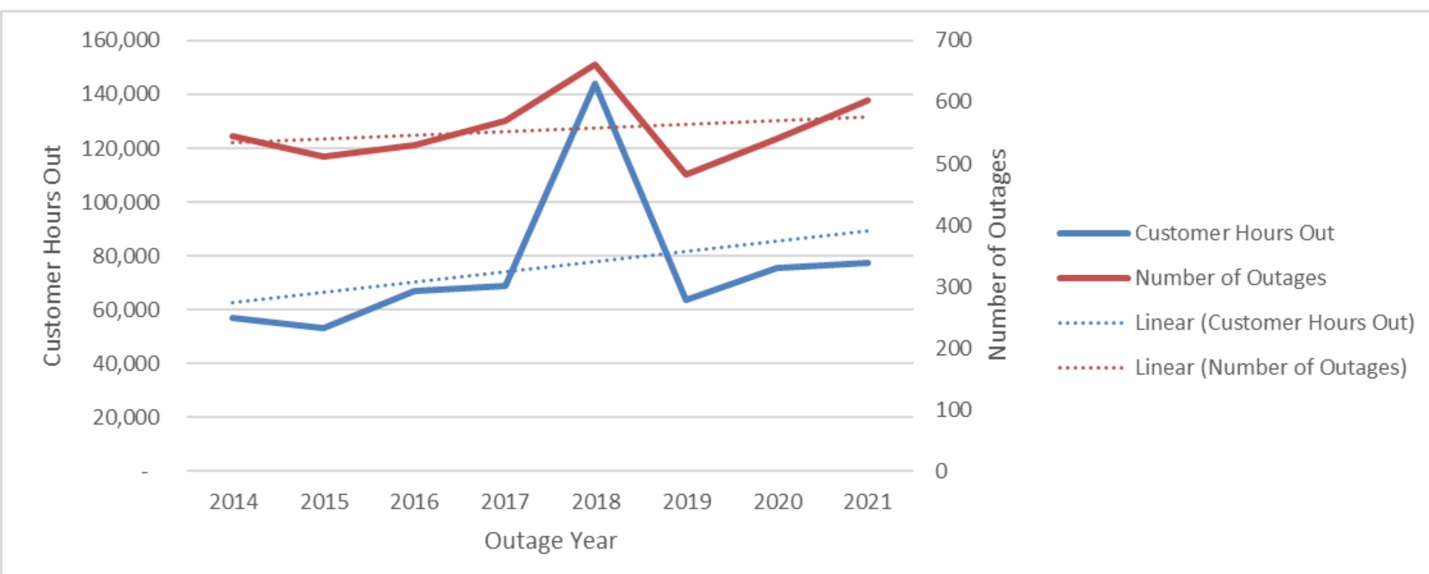


Figure 7.1.1.B VEC's weather related outages 2014-2021

7.1.1 General Overview

Reliability Assessment

- Statistics
- Weather and Climate
- Major Events

Outage Management and Event Response

- Software
- Forecasting
- Response

Maintaining a Reliable Grid

- Maintenance
- Vegetation Management
- Worst Performing Circuits

Investing in a Resiliency

- Grid Hardening
- Microgrids
- Expanding our ability to connect to HQ in a capacity deficiency scenario

7.2 Assessment

7.2.1 Outage Statistics

The following section contains a detailed assessment of VEC's 2017-2021 outage performance. This assessment follows PUC 4.900 definitions and as such, the outage information only includes outages greater than five minutes. Major event outages, such as wind and ice storms, are excluded from the data but are described further in the Major Events section below. VEC files a 4.900 outage report annually and these reports are available for review on VEC's website.

VEC has two reliability-related Service Quality and Reliability Plan (SQRP) goals for System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI).

	SQRP Goals
SAIFI	**2.5**
CAIDI	**2.6**

Table 7.2.1.A VEC SAIFI and CAIDI SQRP goals

VEC's SAIFI and CAIDI five-year averages, excluding all major storms, were 1.89 and 1.90, respectively.

	2017	2018	2019	2020	2021	5 Year Average
Total Members	38,538	38,982	39,179	39,539	39,961	
Number of Outages	1,577	1,860	1,455	1,708	1,660	1,652
# of Members Out	66,137	91,374	58,537	64,548	76,284	71,376
Customer Hours Out	131,392	199,287	111,279	104,405	143,386	137,950
CAIDI	1.94	2.54	1.49	1.62	1.88	1.89
SAIFI	1.72	2.34	1.90	1.63	1.91	1.90

Table 7.2.1.B Total members, # of members out, customer hours out, CAIDI, and SAIFI by Year

The chart below details VEC's outage durations and quantity from 2017-2021.

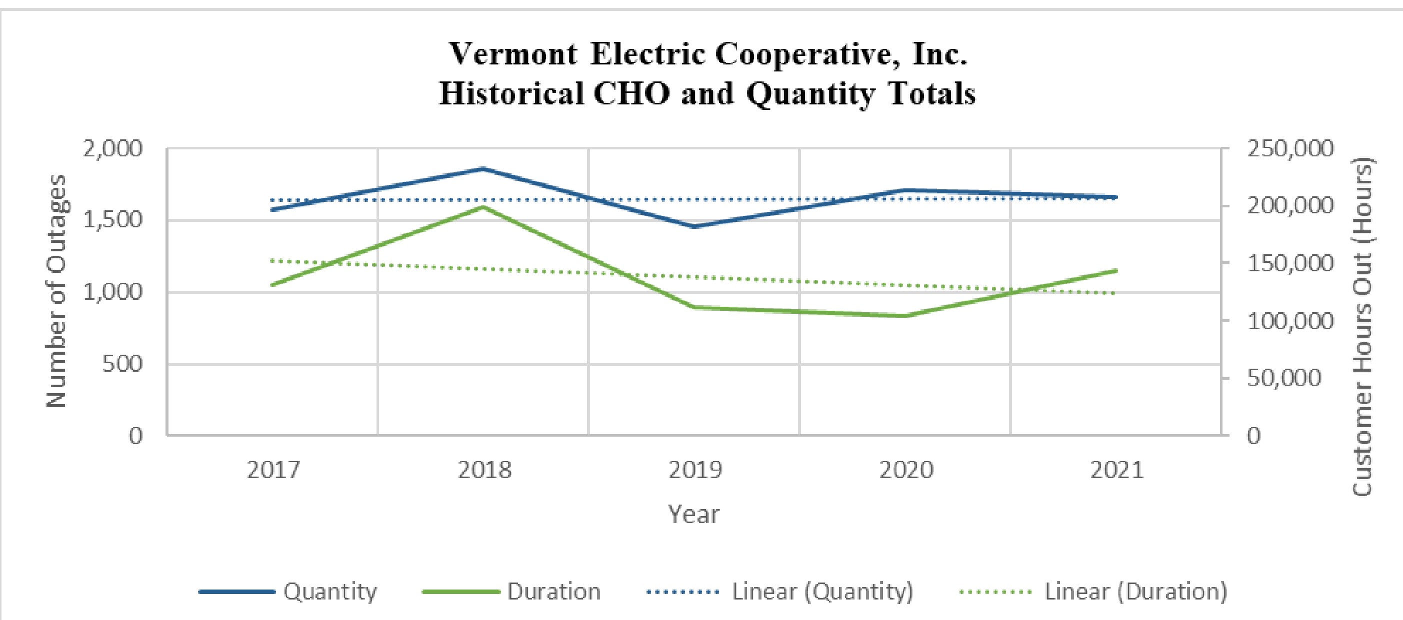


Figure 7.2.1.C VEC historical outage duration and quantity totals

Overall, VEC has seen a decreasing trend in outage duration and a flat trend in outage quantity.

Outage Quantity by Outage Cause

VEC experienced 1,660 outages in 2021 and averaged 1,653 over the five-year period between 2017 and 2021. The chart below identifies outage quantity by cause for 2017-2021.

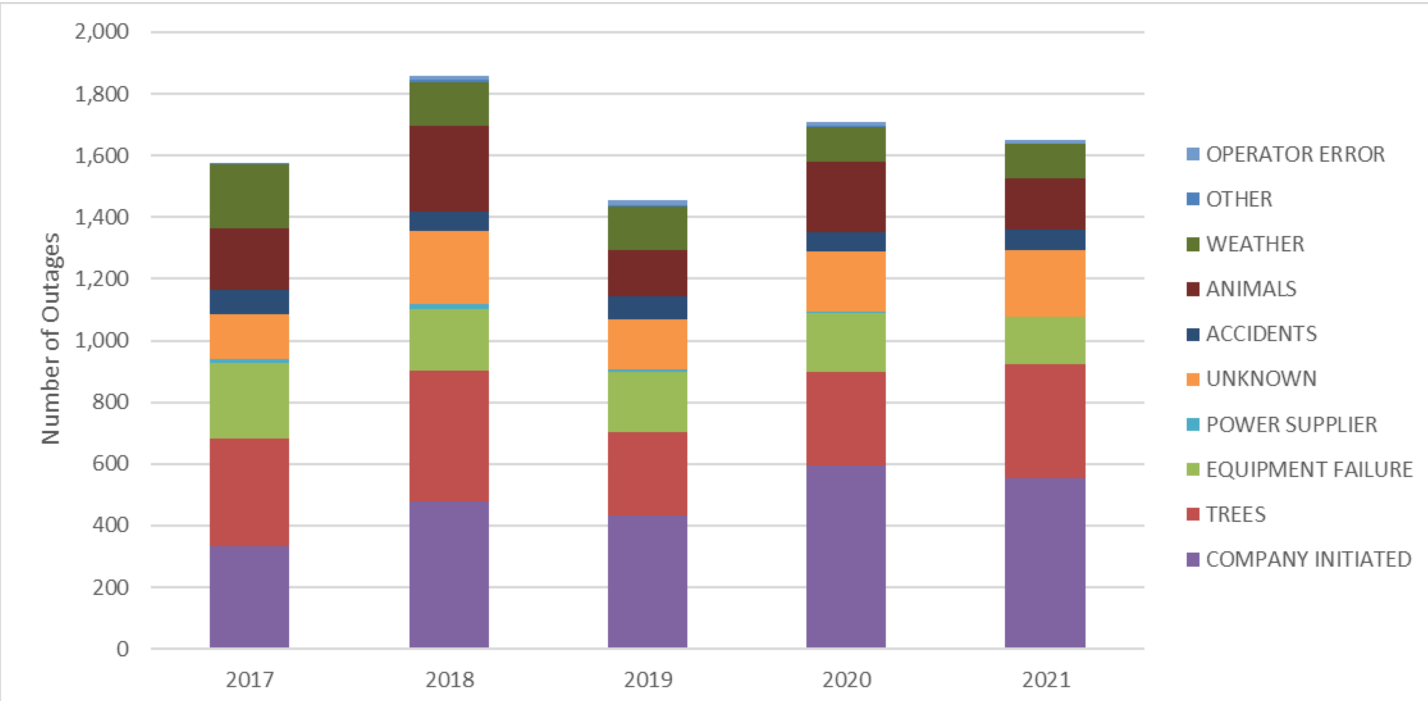


Figure 7.2.1.D 2017-2021 quantity of outages by outage cause

The chart below details the quantity of total outages by outage cause for 2021 and the five-year average.

RANK	CAUSE	2021 (Quantity)	Average (Quantity)
1	COMPANY INITIATED	552	478
2	TREES	373	343
3	UNKNOWN	216	191
4	ANIMALS	165	205
5	EQUIPMENT FAILURE	152	197
6	WEATHER	112	143
7	ACCIDENTS	67	69
8	OPERATOR ERROR	13	12
9	POWER SUPPLIER	9	11
10	OTHER	1	4
11	NON-POWER SUPPLIER	0	0
	TOTAL	**1,660**	**1,653**

Table 7.2.1.E 2021 and five-year average quantity of outages by outage cause

As shown in the table above, company-initiated and tree-related outages continue to be the primary drivers for VEC's outages. Approximately 24 percent (131) of the company-initiated outages were due to outages required for capital projects generally associated with reliability improvements and other initiatives such as installing animal guards.

Regarding the tree related outages, VEC saw a slight increase in tree related outages in 2021 and was slightly above its five-year average for tree related outages.

Outage Duration by Outage Cause

VEC experienced 143,386 customer hours out in 2021 and averaged 137,949 over the five-year period between 2017 and 2021. The chart below identifies outage duration by cause for 2017-2021.

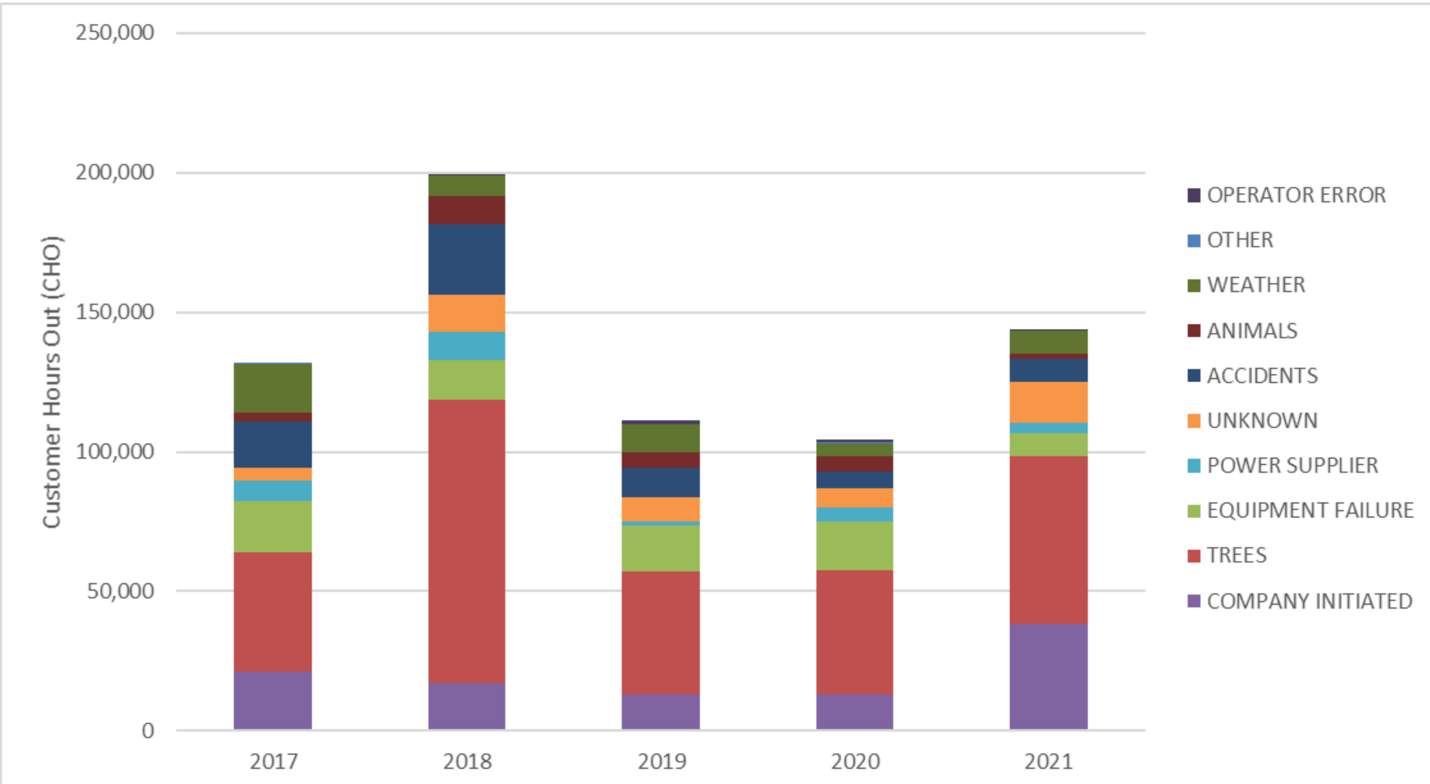


Figure 7.2.1.F 2017-2021 duration of outages by outage cause

The chart below details the duration in hours out by outage cause for 2021 as well as the five-year average from 2017-2021.

RANK	CAUSE	2021 (Hours)	Average (Hours)
1	TREES	60,196	58,515
2	COMPANY INITIATED	38,274	20,609
3	UNKNOWN	14,901	9,732
4	EQUIPMENT FAILURE	8,417	15,043
5	ACCIDENTS	8,230	13,352
6	WEATHER	8,018	9,420
7	POWER SUPPLIER	3,442	5,367
8	ANIMALS	1,790	5,267
9	OPERATOR ERROR	111	594
10	OTHER	7	49
11	NON-POWER SUPPLIER	0	1
	TOTAL	**143,386**	**137,950**

Table 7.2.1.G 2021 and five-year average duration of outages by outage cause

As shown in the above table, tree-related outages are the primary driver regarding customer hours out. In general, all categories except for company initiated outages, equipment failures, and unknowns' outages saw a substantial decline in 2021 customer hours out when compared to the five-year average.

Comparison with Other Utilities

The following is a comparison of utilities System Average Interruption Duration Index (SAIDI) from 2017 to 2021.

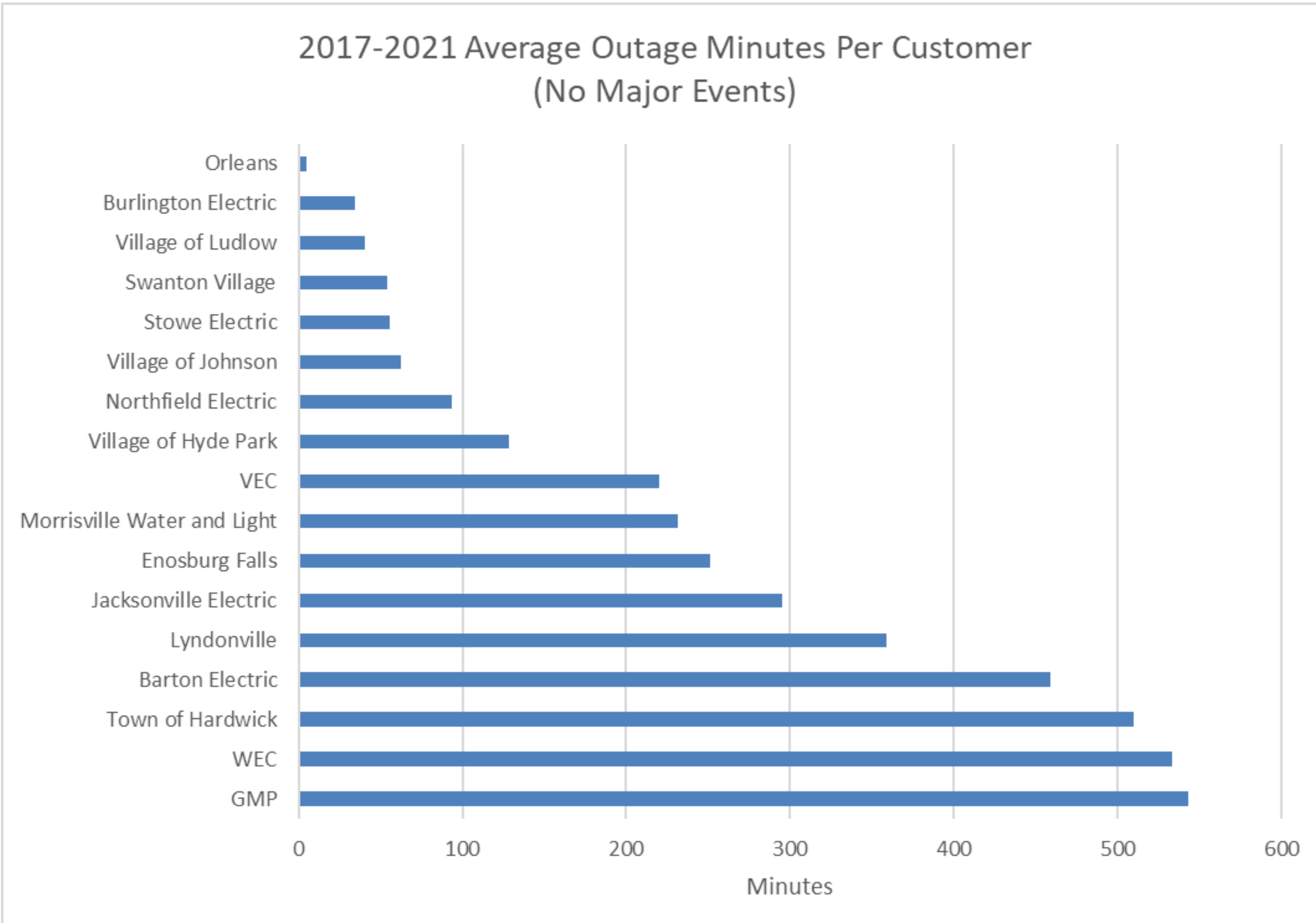


Table 7.2.1.H 2017-2021 SAIDI Comparison to other utilities

VEC ranks ninth out of the 17 utilities that reported data through the ePUC online portal. We have the fewest outage minutes per customer among utilities with less than 20 customers per mile.

7.2.2 Major Events

Since 2017, VEC has experienced four events that qualified as a "Major Storm" as defined in the VEC Service Quality & Reliability Plan (SQRP). As mentioned earlier, VEC excludes these events from VEC's outage reporting. SQRP defines a major storm as a severe weather event that satisfies all three of the following criteria:

- Extensive mechanical damage to the utility infrastructure has occurred;
- More than 10 percent of the customers in a service territory are out of service due to the storm or the storm's effects; and
- At least 1 percent of the customers in the service territory are out of service for at least 24 hours.

The four major storm events are:

- **Winter Storm Phillipe (2017)**
  - Winter Storm Phillipe started on October 30, 2017 at hour 02:00 and ended on November 6, 2017 at hour 20:00. At peak, the storm caused over 21,598 meters to be without power and 459 outage events over the course of the storm. Severe winds with gusts up to almost 80 mph hit the east coast very hard, including Vermont, causing broken poles and knocking down trees and branches onto lines across the state.
- **May Wind Event (2018)**
  - The event started on May 4, 2018 at hour 17:00 and ended on May 7, 2018 at hour 12:00. At peak, the storm caused over 6,344 VEC meters to be without power and 165 outage events occurred during the storm. Over 130 of the 165 outages were tree related as the storm produced 60 mph gusts throughout VEC's service territory.
- **Winter Storm Bruce (2018)**
  - Winter Storm Bruce started on November 27, 2018 at hour 7:00 and ended on December 2, 2018 at hour 20:00. At peak, the storm caused over 14,205 VEC meters to be without power and 522 outage events occurred during the storm. While not a typical storm event from a damage perspective, the storm lasted almost seven days. The storm came in with heavy wet snow, followed by persistent, multi-day, nuisance snow showers of medium density causing snow unloading off lines. Snow unloading occurs when heavy snow accumulates on power lines and causes trees to sag into lines snow unloading causing wires to "bounce" together, or lines to touch (phase to phase or phase to neutral).
- **Halloween Wind and Flood Event (2019)**
  - The 2019 Halloween Wind and Flood Event started on October 31, 2019 at hour 19:00 and ended on November 4, 2019 at hour 19:00. At peak, the storm caused over 18,225 VEC meters to be without power and 327 outage events (290 were greater than five minutes) occurred during the storm. Winds reached gusts greater than 50 mph with sustained winds ranging from 35-45 mph for six hours following three to five inches of rain. The storm caused damage in all eight of the counties VEC serves; trees caused most of the outages.

7.2.3 Minor Events

As VEC mentioned in Section 1 of this IRP and detailed further in the Northview Weather report, the "Overall weather-produced distribution system outage impacts are expected to increase by approximately 6 percent through 2049." While the Major Events discussed above are the most impactful from an outage duration and cost standpoint, VEC's analysis shows that the number of minor storms is trending up for both VEC and GMP. In January of 2021, GMP and VEC collaborated on a multi-year review of the frequency and impact of minor storms to validate this information.

The following chart shows the percentage of total customers out and whether the event was a major storm for both VEC and GMP.

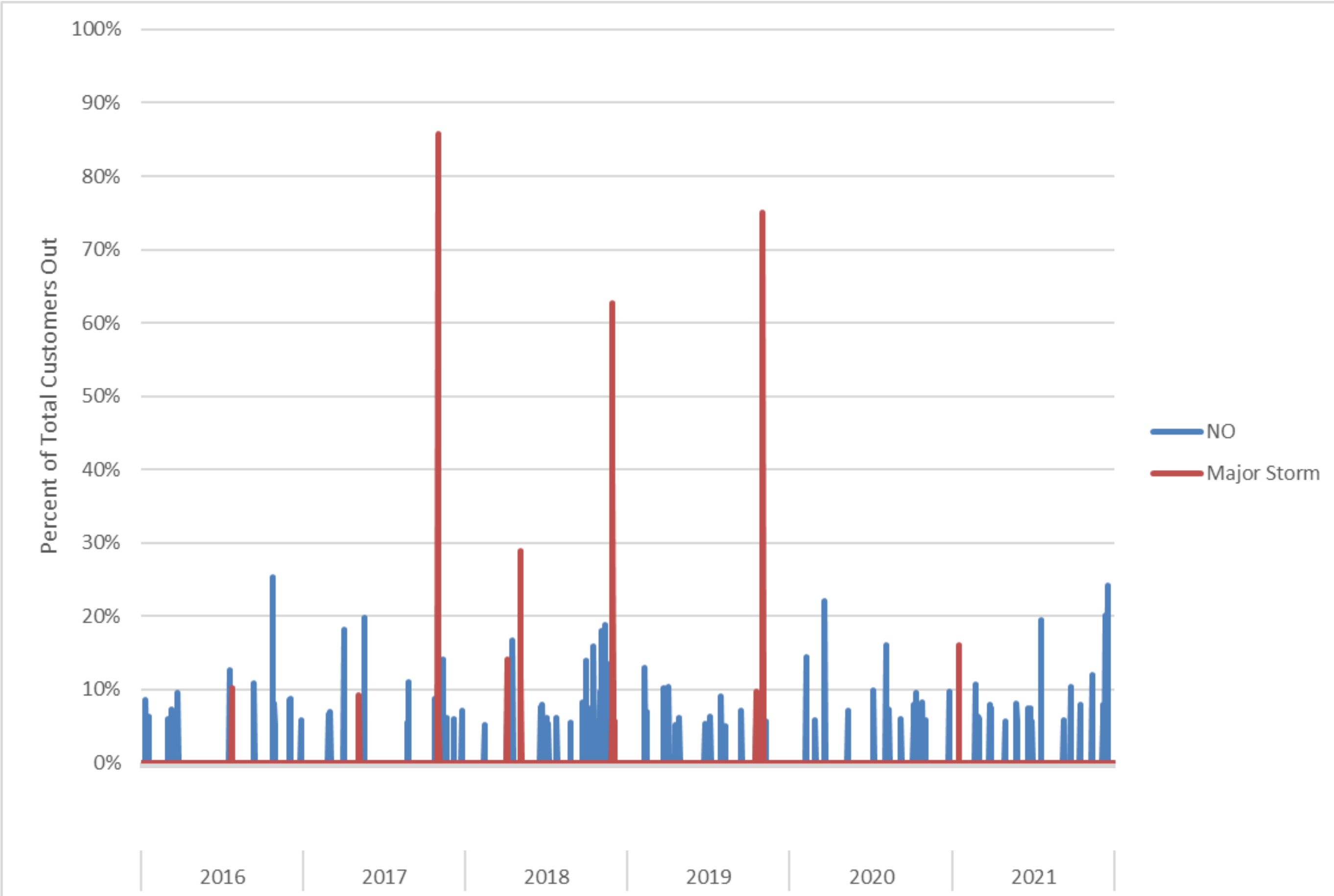


Figure 7.2.3.A Percentage of Total Customers Out Per Day (2016-2021)

VEC defined a minor storm day as any day where at least 2.5 percent of customers were out and there was a minimum of 15 outages for VEC and 75 for GMP

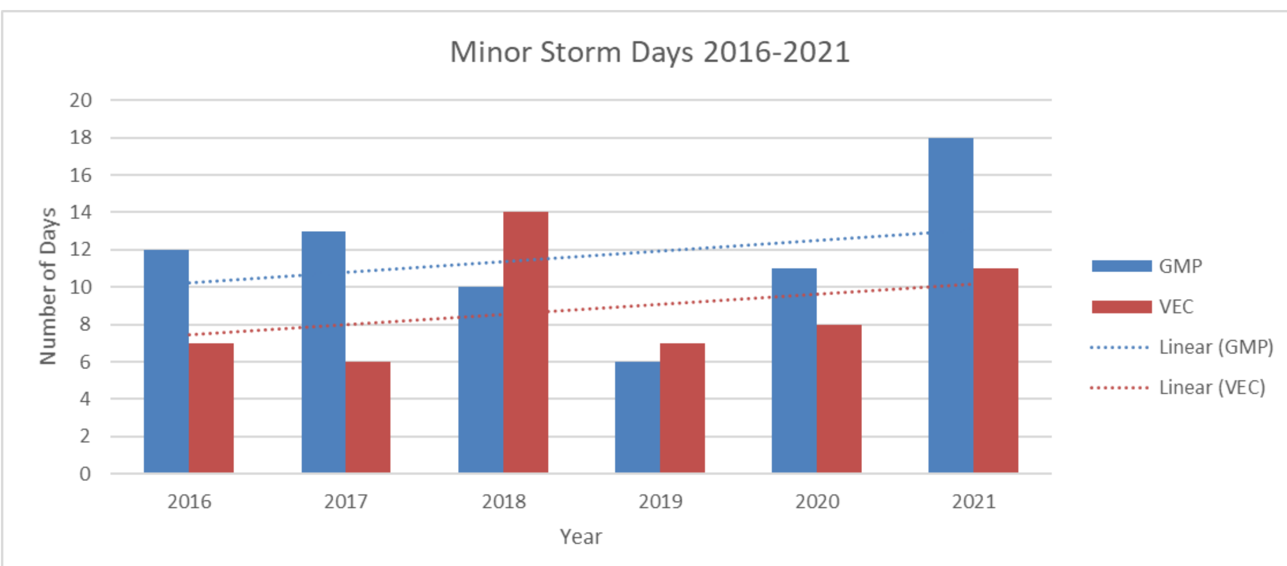


Figure 7.2.3.B Minor Storm Days (2016-2021)

As these minor storm days continue to increase, VEC's priority remains to invest in system resiliency and continue to implement systemwide maintenance of its assets.

7.2.4 Weather and Climate

Weather reflects short-term conditions of the atmosphere while climate is the average daily weather for an extended period at a certain location. Weather (what you get) and climate (what you expect) both have significant impacts to VEC's event response, outage management, and asset planning. As members' expectations of reliability increase, it is important that we expand our monitoring and planning capabilities. VEC has been actively involved in several of weather/climate monitoring/modeling, weather/climate research, and partnership with external companies to understand the challenges and potential solutions associated with weather and climate and to enhance our operational response.

Northview Weather Climate Study

VEC initiated a statewide effort with Vermont distribution utilities and VELCO in early 2020 to identify how our changing climate is affecting weather hazards (primarily wet snow, ice, and wind storms) and to determine the respective impacts to the power system.

Northview Weather LLC was hired, and in August of 2021 produced the Extreme Weather and Climate Change in Vermont: Implications for VEC's Asset and Storm Planning report. The executive summary of the report stated the following:

"High confidence results show that Vermont's climate is warming and becoming wetter, both of which will likely continue to increase into the future. Warmer and wetter storm systems will generally produce storms that are more intense (not necessarily more frequent) and cause more power outage disruptions to the distribution system. Seasonal changes to the warm season show a widening of the summer into early fall, which is expected to continue. This warm season widening will have the effect of lengthening the fall storm season into early winter (over 50% of all power outage impacts occur October to December). Despite a warming climate, the winter season will remain cold enough to sustain wet snow and ice risks through 2049. Overall weather-produced distribution system outage impacts are expected to increase by approximately 6% through 2049.

The distribution system may be affected by more intense storm systems, from wind storms related to inland tracking tropical storms/hurricanes, whose potential intensity will be stronger in a warmer climate. More extreme high temperatures will also tend to shift annual peak loads to summertime…

Heavy precipitation events are expected to continue to increase around twice as fast as annual precipitation. A higher frequency of heavy precipitation events may result in greater widespread flooding risks, especially during the fall season. More irregular precipitation patterns are also likely, potentially leading to more intense drought conditions. However, vegetation health and growth analysis show no clear or strong indications as to how temperature and precipitation changes may affect future tree health and growth."

The following two charts graphically indicate what was described in the narrative above.

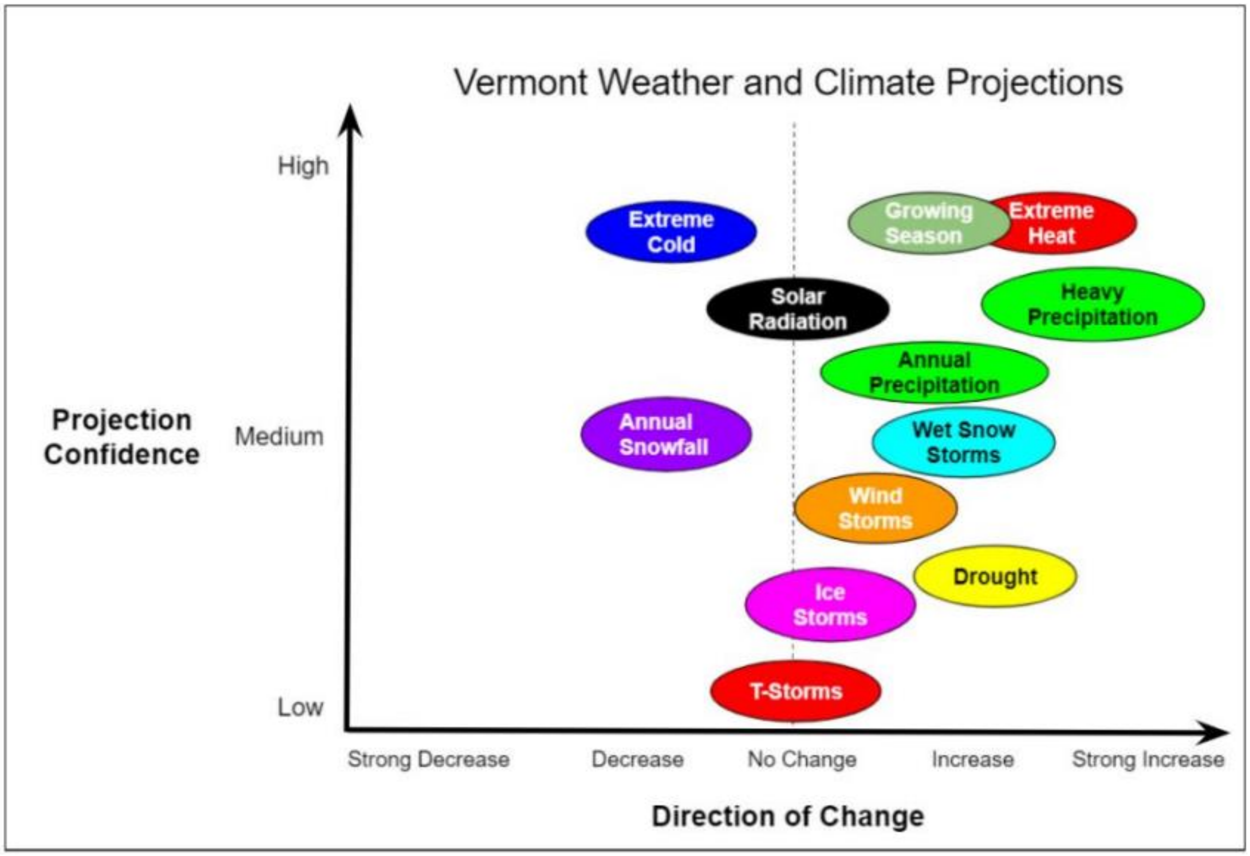


Figure 7.2.4.A. Vermont weather and climate projections with confidence and direction of change.

VEC Power Outage Risk Profile Projection: 2020 to 2049

Hazard	Fraction of Outage Risk	Frequency Change	Intensity Change	Projection Confidence	Overall Risk	Overall Risk Change %
Wind Storms	55%	0	+	Medium	+++	+3 to +5%
Wet Snow Storms	32%	+	+	Medium	++	+8 to +12%
Ice Storms	13%	+	0	Low	+	0 to +2%
				Overall Risk Change		+5 to +7%

Table 7.2.4.B Statistics on outage hazards and projections to 2049.

Weather Observations

Weather observations and forecasts for temperature, precipitation, and wind data are extremely valuable to VEC, especially during outage event planning and restoration. Since 2016, VEC has been working with MesoWest to increase the quantity and accuracy of weather data acquisition throughout northern Vermont.

VEC has installed seven weather stations at its substations throughout its service territory. Each of these weather stations utilize a high accuracy Lufft WS600 UMB sensor that can measure temperature, relative humidity, precipitation intensity, precipitation type, precipitation quantity, air pressure, wind direction, and wind speed. This sensor is connected to a Columbia Weather Systems MicroSever, which allows for data collection and connection to University of Utah's MesoWest project, which then allows the information to be to be utilized by the National

Weather Service (NWS). VEC also utilizes the information internally and sends the information to Weather Underground.

7.3 Outage Management

VEC uses several tools to plan for and respond to outages as quickly and effectively as possible.

7.3.1 Outage Management System (OMS)

VEC has used an Outage Management System (OMS) supplied by the National Information Solutions Cooperative (NISC) since February 2008. The system relies on four inputs:

1. AMI meter information provided by Aclara.
2. Integrated Voice Response (IVR) automated phone system data.
3. Member service inputs from the VEC Member Service Department.
4. Inputs from VEC's external overflow call center (CRC - Cooperative Response Center).

The system is initiated by an outage call from a member or by the VEC Control Center. The OMS system then begins to "ping" surrounding AMI meters from that member until power is detected. The process for identifying the location of an outage normally takes between 30 seconds and two to three minutes depending on the size of the outage.

VEC publishes these outages to vtoutages.com and posts every outage on its website (https://www.vermontelectric.coop/outage) with an estimated time of restoration (ETR). VEC updates the outage information every five minutes, which balances the needs of members to be informed with the stress on the OMS system of more frequent updates.

In addition to the online member facing information, VEC employees can view and update outages on their mobile devices through NISC's AppSuite.

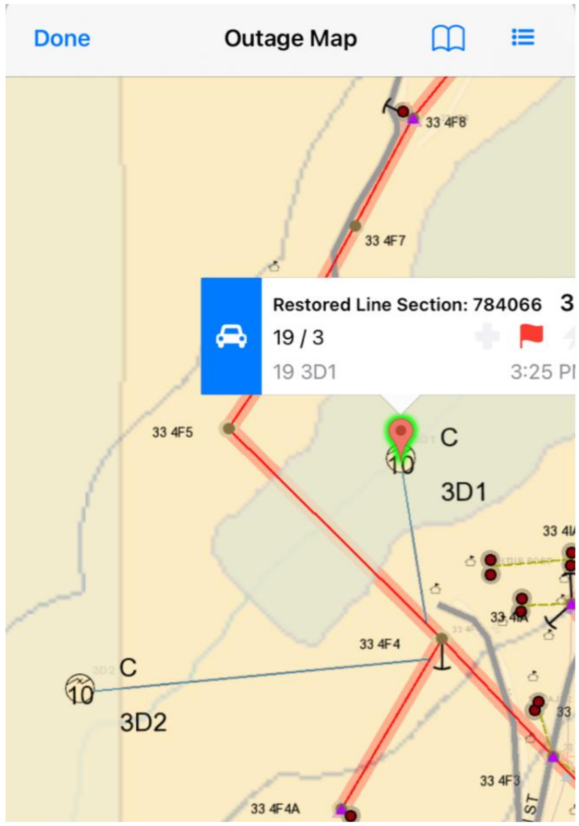


Figure 7.3.1.A VEC AppSuite Outage Response

7.3.2 Outage Forecasting

NorthView Weather Outage Forecasting

In 2017, VEC began working with Northern Vermont University - Lyndon and its subsequent startup, Northview Weather LLC, focused on enhanced approaches to utility forecasting. Northview Weather LLC continuously updates their development of these forecasting tools to provide electric utility operators with reliable and actionable forecast information in meaningful formats without the need to assimilate large quantities of numeric data typically processed by a meteorologist.

These tools will significantly reduce the time that utility personnel will spend to analyze the weather forecast, and they will also allow for more efficient and effective response planning. Highly accurate temporal and spatial forecasts allow utility management to plan for the appropriate personnel and to deploy those personnel to targeted locations prior to the event. In addition, Northview Weather LLC is also developing systematic verification to understand storm performance metrics such as the accuracy of the forecast and the resilience of grid held to weather hazards. An example of one of these forecasts is shown below:

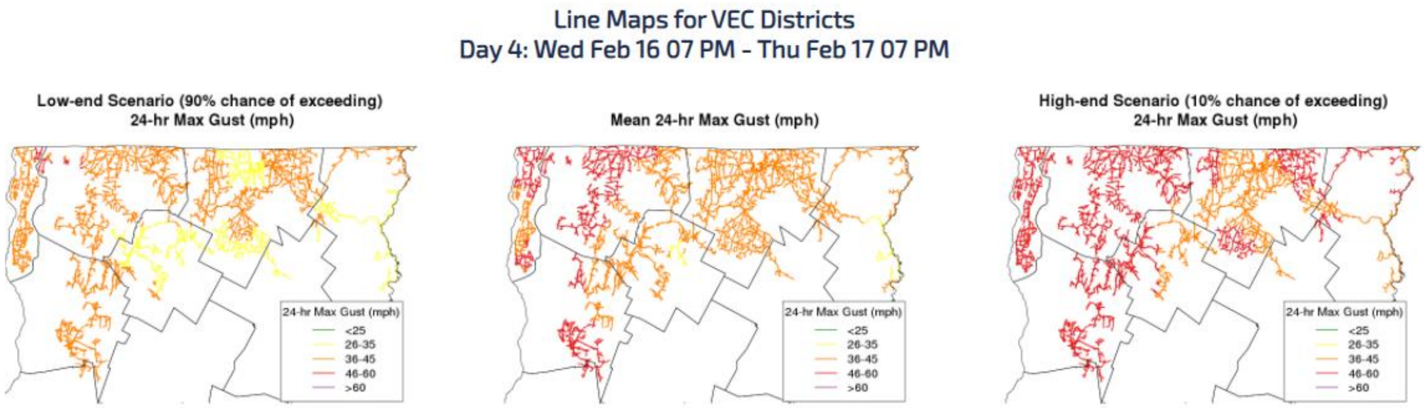


Figure 7.3.2.A NorthView Weather online portal forecast.

Roger Hill Weather Hazards Outlook

VEC receives routine updates from Roger Hill of Weathering Heights with information that ties back to the Northview Weather LLC platform discussed above. In addition to a detailed description of the weather threats, Roger provides video summaries that helps VEC adequately plan for outage events.

	5-6 DAY Outlook and Risk levels for Utilities					
Issued 1/28/2022 9:25 AM	Day 1 FRI	Day2 SAT	Day3 SUN	Day4 MON	Day5 TUE	Day6 WED
Gradient wind gusts		?	?			
Light to possibly moderate snowfall		?	?			
Minor wet snowfall						?
Arctic Chill	?					
Good project Weather			X	XX	XX	
Best Solar			X	XX	X	
Confidence						
	Weather Risk Assessment					
	None	Weak	Moderate		High	
		Confidence Level				
		Low	Moderate		High	

Figure 7.3.2.B Roger Hill Weather Hazards Outlook

Assurance and Disastertech

Communication and data sharing are imperative to manage events and incidents effectively. VEC currently leverages several software platforms comprised of an enterprise notification software Assurance Notification Manager from SunGard Availability Services providing two-way communications via several modes (e.g., text, email, voicemail, etc.) on a company-wide scale, several lists and pages on Microsoft's SharePoint to manage staff availability and various emergency response information, and other software from National Information Solutions Cooperative (NISC) to manage Service and Work Orders, Outage Management and Mapping, and Customer Management (e.g., member inquiries).

While VEC has successfully managed several major and minor events since 2017 utilizing these software packages, we are always looking to streamline the process, make improvements, and enhance effectiveness. As such, VEC participated in the 2021 Electric Power Research Institute (EPRI) Incubatenergy program which combines electric utility experts, other industry experts, and EPRI employees to evaluate new technologies and innovative startups. From that program, DisasterTech is a software application which helps to replace legacy systems using a cutting-edge platform, Artificial Intelligence (AI) computer learning, and predictive analytics. VEC has chosen to pursue leveraging DisasterTech to combine several software applications into a single platform and enhance VEC's responsiveness to events.

DisasterTech integrates directly into Microsoft Teams to allow the seamless sharing of reports, dashboards, and data across the VEC team to maximize situational awareness necessary to make the best possible decisions. DisasterTech also utilizes open source rather than proprietary data, enabling teams to easily share within an organization, or between organizations, while maintaining one common operating platform. The software was founded by several individuals with extensive FEMA experience and integrates directly with FEMA databases and forms to make applications for FEMA reimbursement streamlined. Outside of the collaboration tools inherent with Microsoft Teams (virtual and video calls, real-time chat, file and other information sharing, lists, action items, and a host of other tools), DisasterTech also offers an enterprise communications system like Assurance that can be leveraged for group two-way communications (e.g., cellular, pagers, LAN lines, email, etc.) This is all included in one package eliminating the need to use several software platforms and SharePoint pages, ultimately reducing complexity. Finally, DisasterTech's price point makes it an attractive alternative to using many different software applications, ultimately saving VEC's membership money.

In the first half of 2022, VEC plans to migrate from the Assurance platform for group communication to DisasterTech. Once that migration is complete and employees trained, during the remainder of 2022, VEC will migrate the various forms and lists from SharePoint into the DisasterTech framework and leverage the other FEMA and ICS forms native to the DisasterTech. Our goal is to complete this migration and employee training before the end of October 2022.

7.3.3 Outage Response

Emergency Action Plan OP-57 and Storm Response

VEC Operating Procedure (OP)-57 documents procedures for responding to threats to the reliability of the power system. While these threats tend to be primarily weather-related outage events, the plan includes responses to natural disasters, cybersecurity threats, and acts of sabotage. The plan identifies an organizational structure and processes for initiating preparedness actions based on the level of threat. The OP is patterned after the FEMA based Incident Command Structure (ICS).

VEC categorizes events into four Emergency Planning Levels (EPL): Green (No Concerns), Yellow (Medium Concern), Orange (Probable), and Red (Imminent). An Orange or Red EPL level initiates the ICS, lower level EPL levels are handled by an event manager. Once a VEC publishes the status on its intranet, it communicates changes in status to VEC employees via a variety of communication methods (e.g., email, text, pager, etc.). As new weather forecasts or other threats develop that change the EPL, VEC updates it accordingly. EPL levels are described further in Appendix-C of this document. Establishing and adjusting the EPL Levels, and the corresponding response from planning (Green/Yellow) to response (Orange/Red), is at the discretion of the Event Manager/Incident Commander with reference to the EPL Criteria and in consultation with Operation and Planning Section Chiefs. At least for the General and Command staff, there is at least one primary and one backup individual well trained to handle the requirements of those positions. In other areas, a backup may not yet be available. VEC continuously looks for improvements of the system and enhance personnel training.

VEC uses numerous weather sources and its experience from past events to predict both outage magnitude and duration. VEC uses a weather predictive resource coordinated by VELCO, which is monitored closely by System Operations. VEC also participates in the statewide utility emergency calls and internal calls/communication before and during larger events. In addition, depending on the EPL and following OP-57, VEC will create internal crew rosters for each event based on the available personnel and estimated type and duration of damage. Finally, VEC will determine external crew requirements and bring in crews from both in-state and out-of-state contractors and companies.

Mutual Aid

If external crews are required, VEC will reach out to a set of pre-defined contractors as well as request aid from local cooperatives and utilities, utilities from other states, or the National Guard. External crews attend VEC's safety briefing, are led by VEC qualified personnel, and provided with VEC-specified material and GIS mapping tools.

Finally, VEC also offers Mutual Aid assistance to other utilities both inside and outside the State of Vermont with the following guidelines:

- Any utility in Vermont, New Hampshire, Maine or New York.
- Cooperatives up to a 500-mile radius of Johnson, VT.
- Municipals in any New England state.

For more information, see OP-57 in Appendix-B.

Notification of Planned and Unplanned Outages

VEC knows that the availability of electric service is of primary concern our members. We look to minimize outages, but also to look to provide excellent communication when outages do occur and ensure that any company-initiated outages create the least possible inconvenience. VEC OP-59 identifies those interested in receiving outage information, defines outage notification criteria, and identifies the proper communication methods depending on the type of work.

In addition, VEC ensures public safety by adhering to the following criteria for company-initiated outages based on temperature ranges. These criteria are guidelines and will be considered on a case-by-case basis. Heat index and wind chill are also considerations.

Company Initiated Outages		Planning Criteria
>40 °F	**<80 °F**	No Restrictions
33-40°F		Limit to 4 Hours Max
20-32°F	**80-84 °F**	Limit to 2 Hours Max
0-20°F	**85-90 °F**	Limit to 1 Hour Max
<0 °F	**>90 °F**	Not Allowed

Table 7.3.3.C Planning criteria for company-initiated outages based on temperature

During a non-major, event-related, unplanned outage, the VEC Control Center notifies all medical priority members by searching the outage location on VEC's Customer Information System (CIS). The VEC Control Center will also attempt contact priority members such as large businesses or other members that have requested to be on this list.

For more information, see OP-59 Appendix-D.

7.4 Maintaining a Reliable Grid

Maintaining our assets and facilities is critical to keeping the lights on. The following section describes VEC's maintenance and practices that help reduce outages on the system.

7.4.1 Our Reliability Strategy and Priorities

In regards to reliability our strategy and priories are as follows:

1. **Explore satellite imagery Vegetation Management strategies and use of drones** – Over the past 13 years, VEC executed its plan with a commitment to meet annual mile targets while remaining flexible to address immediate safety, reliability, and member concerns (e.g., hot spotting, danger trees, and Emerald Ash Borer). We are looking into satellite-powered vegetation management options to reduce costs and improve reliability. Satellites can provide in-depth monitoring of transmission and power lines and right of way encroachments from space with the goal of automating decision making to cut down on O&M costs.

2. **Continue systemwide Maintenance Plan and condition-based assessments/replacements –** We are almost finished with our third year of five years assessing and replacing assets throughout our system. Doing proactive maintenance through our systemwide Maintenance Plan will extend asset life in the long run and reduce preventable outages.

3. **Expand outage management technologies and strategies for faster restoration -** Our outage management technology is fundamental to outage response and we continually seek new ways to identify and respond to outages quicker. Through implementing our ICS management platform Disastertech and further expanding our OMS we hope to meet those targets.

4. **Monitor system protection as load continues to grow.** Our system is well sectionalized and protected which has reduced the number of members impacted during an outage event. With 50-60% load growth projected on the system we will need to continually monitor the impacts to system protection to ensure reliability.

7.4.2 Vegetation Management

VEC has a responsibility to maintain vegetation on its system to preserve the safety and integrity of our overhead electric facilities. Since 60-70 percent of VEC's distribution lines traverse cross-county locations in remote parts of Vermont, VEC's system is especially vulnerable to heavy snow, ice, and wind events. Much of VEC's system was constructed in the early to mid-1900 when much of Vermont was open pasture or land. Utility lines were constructed as the shortest distance between two points to save on costs. Our Green Mountain State takes pride in our green trees, but electricity and trees do not mix well, so we work to maintain a safe, reliable system while also maintaining a healthy and beautiful Vermont.

In 2009, VEC filed a vegetation management plan that addressed funding, maintenance cycles, and performance execution. That analysis identified a transmission right-of-way (ROW) maintenance cycle of five years and distribution ROW cycle of eight years based on then industry best practices and VEC's experience of managing utility ROWs in Vermont. Due to the rate impact associated with moving directly to an eight-year distribution cycle, VEC and the Department of Public Service agreed that VEC would achieve an eight-year cycle over a period of a cycle and a half, or twelve years. The PUC accepted this agreement.

Over the past 13 years, VEC executed its plan with a commitment to meet annual mile targets while remaining flexible to address immediate safety, reliability, and member concerns (e.g., hot spotting, danger trees, and Emerald Ash Borer). The plan has proven to be effective, with VEC achieving a five-year cycle for transmission ROWs and reaching the end of its twelve-year path to achieving an eight-year distribution cycle. However, recent trends in reliability metrics show that tree-related outages continue to increase. VEC was able to make relatively quick improvements in the early years of its vegetation management program cycle. However, after almost completing two cycles of transmission ROW clearing and with the first cycle of distribution ROW maintenance 75 percent complete, the improvement in outages from tree related outages is slowing.

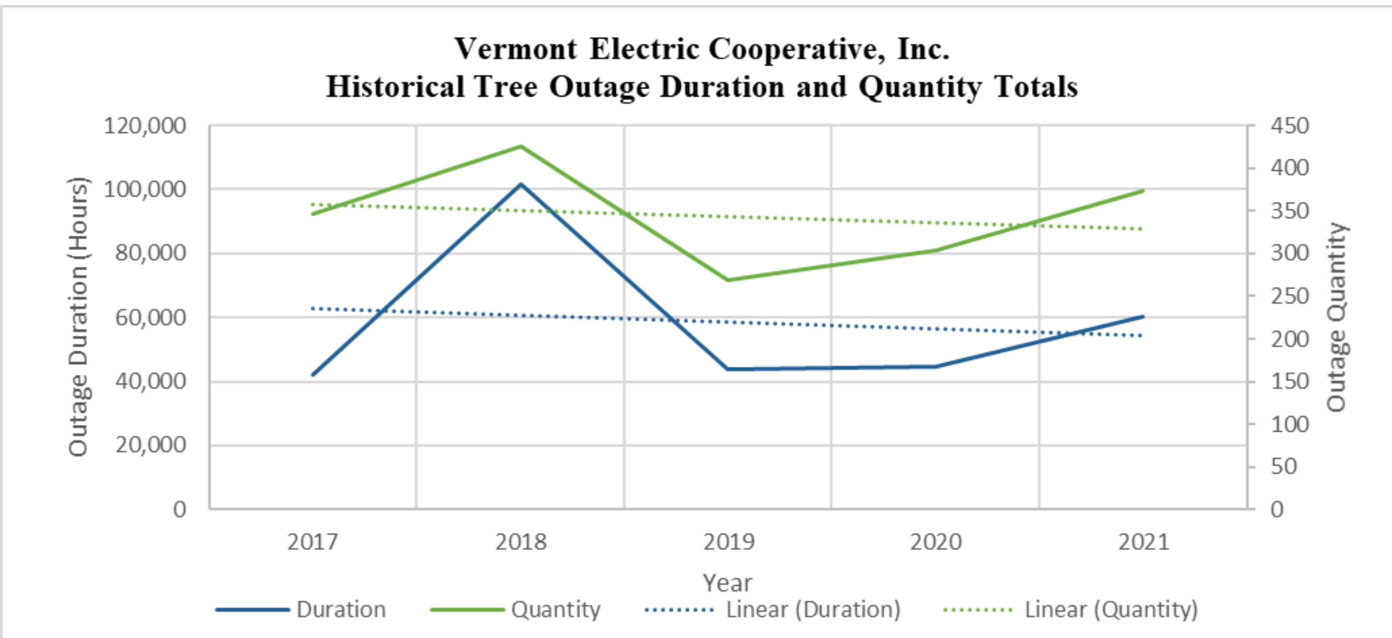


Figure 7.4.2.A Historical tree outage duration and quantity totals

In 2018, VEC hired Arbor Intelligence to conduct a comprehensive review and assessment of its Vegetation Management Program. The assessment included a random sample of VEC's system using the Arborcision ™ stratified random sampling method and used the findings to assess the system's status.

Their report addressed the following:

- Current Vegetation Maintenance Practices
    - Cost effectiveness
    - Impact on reliability
    - Impact on safety (members, public, employees, contractors)
- Established maintenance cycles on transmission and distribution systems
- Vegetation maintenance specifications
- Vegetation Management Plan – review and provide recommendations for areas of improvement
- Record keeping
- Contract strategy, administration, and management

- Current and proposed future funding levels
  - Recommended spending levels that consider impact on rates and
  - Reliability to achieve an optimum spending level that balances these two
  - Key metrics
- Staffing
- Overall program implementation and management
- Adherence to national standards such as National Electrical Safety Code (NESC) and National Rural Electric Cooperative Association (NRECA) Cooperative Research Network (CRN) vegetation management principles
- Comparability to others in the industry (specifically to other Cooperatives with similar line miles, topography, and vegetation types)
- Comparability of safety rules – review and make recommendations based on what other utilities do regarding outages caused by vegetation maintenance actions (e.g., three day stand down for any contact with electric facilities)

The Arbor Intelligence Report confirmed what VEC has observed from its own analysis and outage metrics: VEC's current distribution cycle is too long given the vegetation in our service area. Arbor Intelligence analysis recommended a four-year distribution maintenance cycle to achieve a true maintenance mode with a balanced workload composition and maximize the cost effectiveness of vegetation maintenance activities. However, as shown by VEC's own internal analysis from 2009, moving to a more aggressive cycle has significant impacts to costs and thereby rates on the front end even if costs over time are lower. Overall, the report demonstrates that an eight-year trimming cycle is too long, if we want the most reliable and cost-effective Vegetation Management Program.

Opting to fall between these two extremes, VEC adjusted its current plan to move to a six/seven-year blended cycle by the year 2023 by slightly increasing the number of miles of line cleared per year over time, rather than a one-year rate impact. A "blended" cycle means that instead of VEC maintaining its entire service territory on a standard cycle, some of the system will be on a six-year cycle and some of the system will be on a seven-year cycle, depending on the type of construction, vegetation growth rates, and successful use of herbicides in selected locations. Further consideration for this blended cycle explored the following criteria:

- Worst performing circuits
- Type of construction (3 phase warrants shorter cycle)
- Arbor Intelligence data/recommendations
- VEC Vegetation Management team's knowledge and experience of system/territory
- Date last cleared

This plan has been decelerated to some extent, by the increased pressures of the Covid-19 Pandemic, but VEC's plan is to achieve a blended six/seven-year blended cycle in the next three to five years.

<u>VEC Environmental Guidance Manual</u>

Near the end of 2021 and beginning of 2022, the areas of ROW and Environmental Guidance joined VEC's Vegetation Management Department. At that time, VEC contracted with an environmental consulting firm to prepare an Environmental Guidance Manual (EGM) to support the installation, operation, and maintenance of transmission and distribution lines. The EGM will be used by VEC employees and contractors and cover regulatory considerations, project planning and scoping, procedures associated with project review, field assessment, typical natural resources and practices, hazardous materials, training/project compliance, and best management practices. Specific natural resources to be addressed include wetlands, streams, flood hazard areas, river corridors, rare, threatened and endangered species (including bats), known cultural resources, soil disturbance, non-native invasive plant species, and the addition of impervious areas. Completion of the EGM and employee training is scheduled to take place in spring/summer of 2022.

<u>Emerald Ash Borer</u>

A significant impact to VEC's Vegetation Management program is the Emerald Ash Borer (EAB). Vermont has confirmed the EAB is within its borders and specifically in VEC service territory in several locations. The EAB is a beetle that has devastated ash trees in states across the U.S., costing communities millions of dollars. Infested trees rapidly decline and die within 3-5 years. VEC faces a severe risk from a sudden wave of hazard trees along electric utility lines. Ash trees account for approximately five percent of all trees in Vermont or approximately 150 million ash trees across the state. VEC estimates there are approximately 750,000 ash trees within potential striking distance of VEC's overhead transmission and distribution electrical power lines. In 2021, it cost VEC an average of approximately $179 per tree removal. Other utilities that have already experienced the impacts of EAB infested ash trees report it potentially costing more than two times the normal cost to remove dead and dying infested ash trees. VEC has applied for outside funding for EAB response, but has not been successful in obtaining such funding, to date.

Figure 7.4.2.B Emerald ash borer

EAB is known to be present in 35 states in the U.S., and utilities and communities through the U.S. are implementing response/mitigation plans to address the negative economic, social, and environmental impacts. EAB has continued to spread throughout Vermont and VEC's service territory over the past several years. While there have been some efforts to introduce species of wasps, known to be natural predators of EAB larvae, to slow the spread, there is no known cure. A single EAB can travel a half mile per year, with the potential to expand the range of an infestation up to several miles per year during the adult beetles' June to August flight period. Moreover, human transport has led to the spread of EAB over much greater distances.

In addition to the threat to Vermont's electric grid, due to the increase of potential hazard trees within striking distance to power lines, EAB and the death of Vermont's ash trees will have a variety of adverse impacts. The presence of so many dead and dying ash trees will be aesthetically damaging to a state known for the beauty of its forests and wooded hillsides. The dead trees tend to rapidly deteriorate and pose a safety threat to Vermont residents and tourists, most especially, those who work in and/or around trees. EAB will affect every type of utility and public infrastructure to some degree and the simultaneous death of multiple trees will compound the safety and cost of preemptive measures.

VEC's EAB Response Plan and Mitigation Program includes outreach/education to VEC's members and the communities they live in. In addition, VEC is actively participating on a Vermont Utilities' Emerald Ash Borer coordination team, consisting of representatives from VELCO, distribution utilities, and Vermont state organizations who are responding to this issue.

As part of the 2020 rate case, VEC conservatively estimated the cost to remove all ash trees within striking distance of its line within the current EAB confirmed infestation area to be $2,918,190. This number assumes there are 148 ash trees within a striking distance of VEC line in a linear mile and a $165 per tree removal cost. The cost to remove ash trees exponentially increases as the infestation takes over and the EAB infected trees become too dangerous to remove safely by conventional methods. We requested $250,000 in 2020, or approximately 8.5 percent of the estimated program cost, to begin mitigation/response on VEC's system.

With limited mitigation resources identified for 2020, VEC focused EAB mitigation on implementing guidelines for proactive Ash tree removal in areas where routine scheduled vegetation maintenance activities intersected with confirmed EAB infested and high-risk areas. Approximately $152,583 was spent removing 985 ash trees ($155 per tree). Having identified challenges associated with labor resource constraints and the ability to simultaneously implement EAB Ash removal without negatively impacted the progress of on-going scheduled vegetation maintenance activities within the same operation, VEC deployed dedicated EAB Ash Removal crew(s) in 2021. Approximately $344,492 was spent removing 2,103 ash trees ($164 per tree). VEC will continue to budget at least $250,000 annually for EAB mitigation and will continue to pursue additional funding for EAB response.

7.4.3 Maintenance Plan

VEC initiated its comprehensive system wide maintenance plan (MP) in 2019 to enhance reliability, proactively reduce preventable outages, and ensure compliance with safety codes for VEC's members. The MP is broken up into two major components:

1. A "System Assessment" with the goal of gathering of accurate asset data such as conductor and transformer sizes, manufacturers, serial numbers, proper phasing, attachments, etc. The data is populated in VEC's GIS system via NISC's AppSuite Inspections software utilizing both internal VEC personnel and contractors. **VEC is currently 40 percent complete with its system assessment and expects to complete the project in 2026.**
2. A "Five Year System-Wide Maintenance Cycle "where VEC performs proactive maintenance on the entire system is visited over the course of a five-year period. **VEC is currently 60 percent complete with this maintenance effort and expects to complete the first five-year cycle in 2024.**

VEC and contract resources capture asset and maintenance information through NISC's AppSuite Inspections software which can be populated directly into GIS.

System Assessment

VEC hired Davey Resource Group (DRG) to assess and gather data on the following:

- Pole hardware and third-party attachments
- Conductors
- Street Lights
- Overhead Transformers

Contractors and internal staff use severity ratings to determine the response time. VEC uses the rating system on all assets and varies by asset. When VEC identifies an issue, the appropriate VEC personnel receive the information and fix the issue within an appropriate timeframe. In some cases, a capital project is designed, processed through VEC's prioritization scheme, budgeted, and constructed.

Five Year System-Wide Maintenance Cycle

While the System Assessment is underway VEC personnel will perform assessment on special equipment such as reclosers, voltage regulators, and substation equipment. Each year 1/5 of the system is assessed and equipment replaced as needed.

The plan is discussed in more detail in Appendix-F and includes discussions on aerial patrols, substation testing programs, and more details on distribution inspections.

7.4.4 System Protection

VEC designs its power system protection to automatically detect faults that occur on the system and sectionalize or isolate the faulted lines from the rest of the electrical network. The aim is to improve both worker and public safety, minimize damage, and improve the overall service reliability of the power system while preventing outages for a larger number of members. VEC utilizes the following system protection equipment designed to automatically coordinate with one another to sense system faults and sectionalize or isolate the system closest to the faulted parts:

- Reclosers – Located at VEC's all distribution substations and at various locations throughout the distribution system, these devices are the primary distribution circuit protection and quickly attempt to clear a fault or de-energize an entire circuit to protect the substation transformer and other distribution equipment from damage.
- Line fuses – Located on distribution taps, fuses isolate permanent faults and minimize the size of outages to the smallest possible number of members.
- Transformer fuses – Located on all conventional transformers, these fuses limit the energy released during a short circuit and protect the associated equipment from failing.
- Arrestors – Located on aerial transformers and capacitors, arrestors protect those devices from over-voltage such as lightning.

The design settings of these equipment types aim to reduce the time of fault exposure to the shortest possible to improve worker and public safety, minimize asset damages, and maintain an acceptable level of overall system service reliability.

What is sectionalizing?

VEC's distribution system has many taps or sections, some of which feed commercial/industrial members and some that feed residential members. In the example shown below, a tree falling on the line near member #3 will affect the entire substation causing outages to members 1, 2, 3 and the sugar maker.

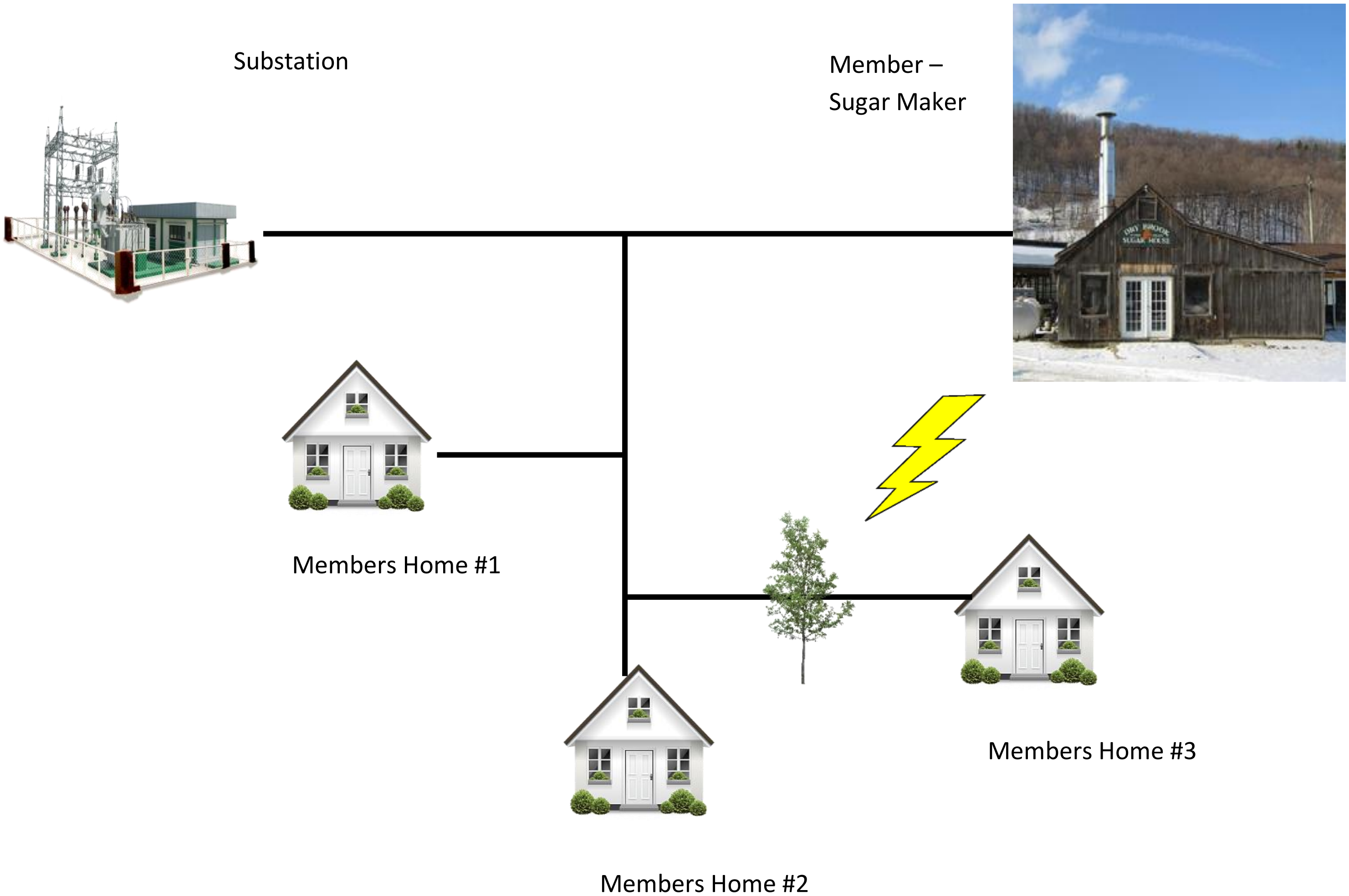


Figure 7.4.4.A Tree falling on line near member #3

With adequate sectionalizing via the installation of fuses 1, 2, and 3, the same fault would only affect member #3 instead of the entire circuit.

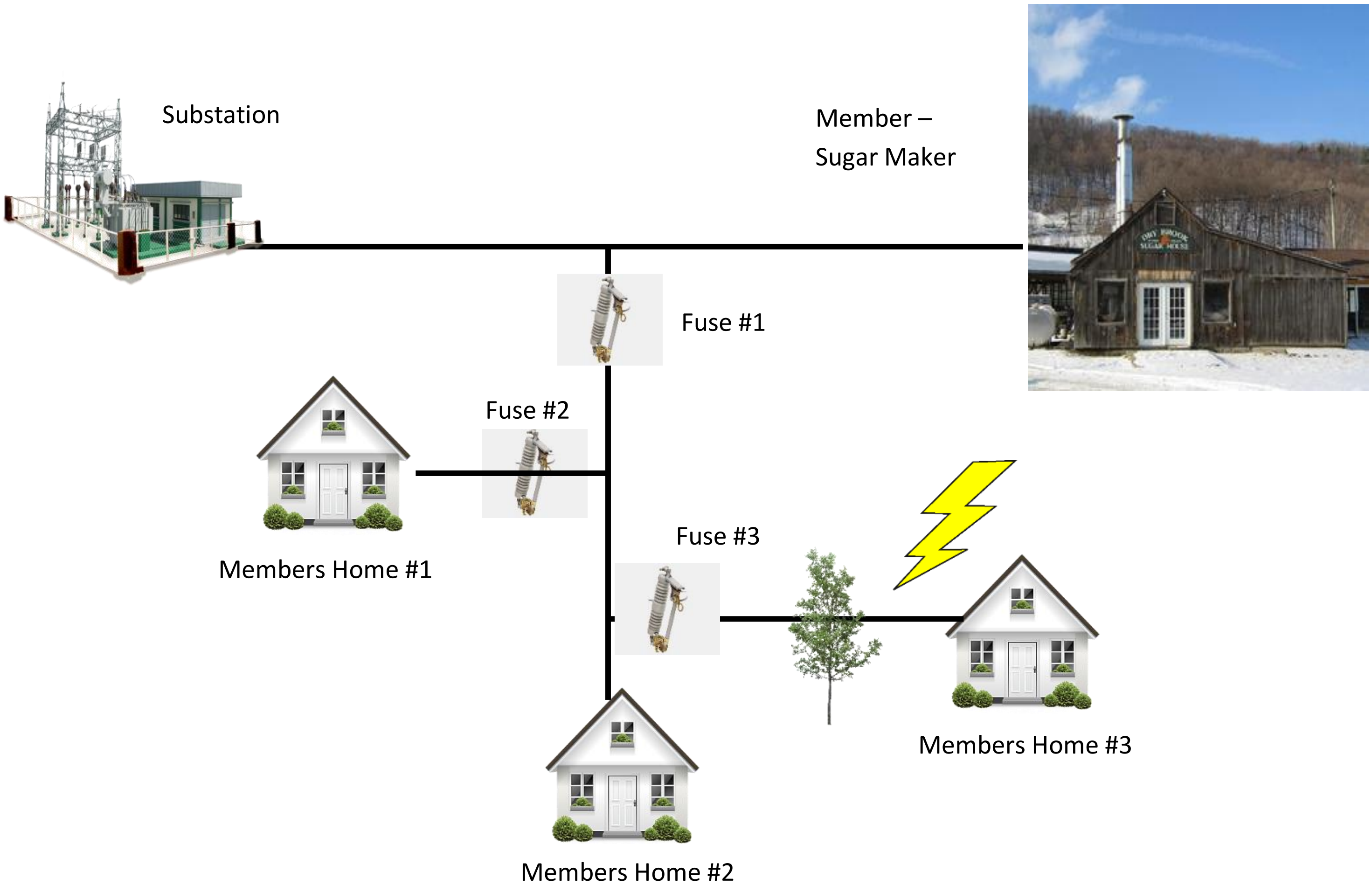


Figure 7.4.4.B Adequately sectionalized circuit

Extensive studies of overhead distribution systems established approximately 80 to 95 percent of all system faults are temporary and last from only a few cycles to a few seconds. A single recloser operation opening and reclosing helps keep these temporary type faults from becoming a longer outage. An example of a temporary fault includes an animal or bird contacting an energized line, wind gusts blowing a tree limb into the line, lightning strikes, and snow unloading from tree limbs that are hanging below primary conductors making contact as they spring upwards. Most line faults occur only on a single phase.

VEC continues to have many unfused side or lateral taps within our distribution system. We routinely add fuses to these tap lines to better sectionalize outages and minimize the quantity of members affected by them.

Distribution

VEC completed a comprehensive system protection analysis in 2009 and does an annual review of protection on its top 10 worst performing circuits as reported in the annual 4.900 Reliability Report. In addition, all new projects (generation and load) include a review of existing protection that may identify protection improvements or alterations. VEC sizes new protection to the existing load downstream of the device.

Substation

VEC has standardized on using" triple-single" three-phase electronic reclosers at its substations and on three-phase distribution lines in general. These reclosers are programmable to trip only the phase that experiences a fault without interrupting power to the other two phases. Additional programming allows VEC to either lock open a single phase for permanent faults or lock open all three phases to prevent "single phasing" of sensitive three-phase loads. For many rural substation feeders that have a few or no three-phase loads, it is desirable to lock open only the single phase affected by the fault. VEC recommends that member owned equipment be equipped with a protective device in addition to those required by the NEC to guard damage caused by the following events: loss of phase, under-voltage/over-voltage, or automatic restart following an interruption.

In addition, VEC utilizes overcurrent protection to maximize load current, allow for cold load pickup (significant load demands after an outage), feeder back up configurations, and maintain sensitivity required to keep the system protected from bolted ground faults.

The majority of VEC's substation transformers utilize a high side power fuse for protection. VEC sizes these fuses to carry the full, expected load of the transformer's capacity and protect the transformer from a high magnitude short circuit current between the fuses and the transformer, within the transformer itself and the substation's distribution bus before the feeder protection equipment. The distribution feeder protection equipment protects the transformer from over-loads or faults out on the distribution feeders.

VEC has standardized on using S&C power fuses to protect its substation power transformers. These fuses are very reliable and not prone to preheating allowing for:

- Fusing closer to the transformer full-load current -- providing protection against a broad range of secondary-side faults.
- Higher levels of service continuity – eliminates "sneak-outs" (unnecessary fuse operations).
- Close coordination with other protective devices – no "safety zones" or "set-back allowances" needed to the published time-current curves to protect fuse elements against damage.
- Operating economies -- no need to replace unblown companion fuses on suspicion of damage following a fuse operation.

VEC's substation feeder protections typically do not use "fuse-saving" trip operations, allowing the down-stream line reclosers and fuses to operate and clear faults without causing substation feeder protections to momentarily interrupt power to the entire feeder to save a feeder down-stream line fuse. Where VEC does utilize fuse saving trip operations, we limit the number of "fast" trips to a single operation to limit the momentary interruptions to the members served by the recloser.

Subtransmission

VEC communicates directly with VELCO and GMP regarding what we have planned for substation transformer fuses and transformer sizes interconnected to their transmission systems, including any tap transmission lines owned and operated by VEC that have independent protections installed. VEC does not possess a copy of the transmission or sub-transmission system model and cannot perform these studies on our own without the assistance of VELCO or GMP.

7.4.5 Wildlife Protection

VEC continues to see a decrease in animal related outages which used to account for almost 20 percent of total outages in 2017 and only accounted for less than 5 percent in 2021. Wildlife protection (also referred to as animal guards) deters squirrels and other animals from accessing electric power lines, substations, and transformers resulting in reduced outages.

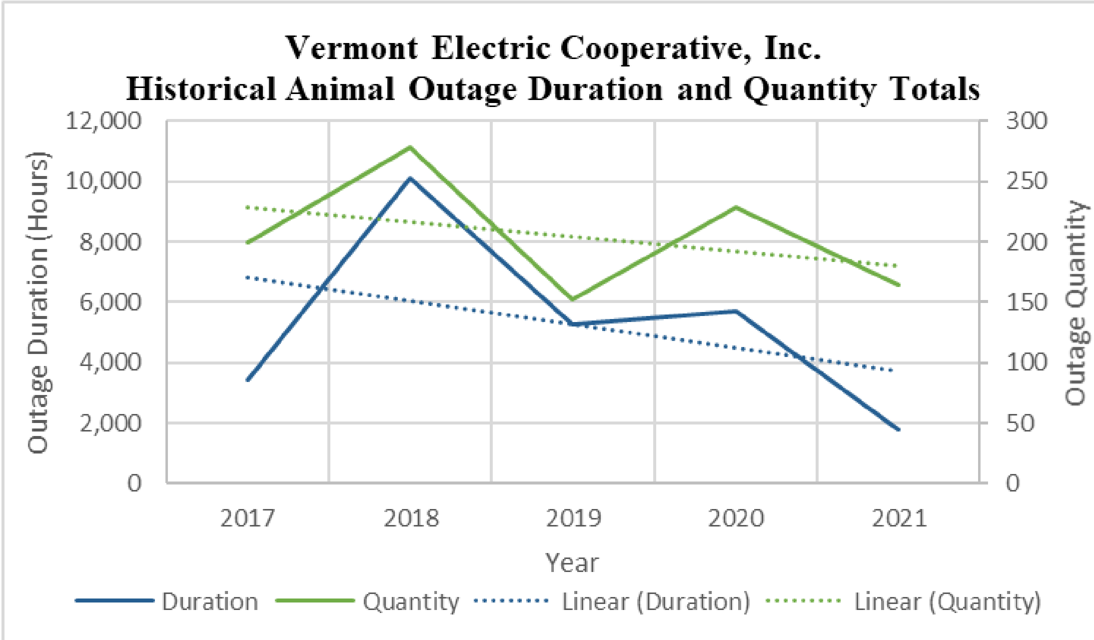


Figure 7.4.5.A VEC animal outages 2017-2021

On its distribution system, VEC adds wildlife protection to all new and replaced reclosers, regulators, transformers and substation equipment. VEC uses a RUS approved Reliaguard product that combines effectiveness and durability while considering the least cost solution. Reliaguard products follow IEEE 1656-2010 (IEEE Guide for Testing the Electrical, Mechanical, Durability Performance of Wildlife Protective Devices on Overhead Power Distribution Systems Rated up to 38 kV), and UL94 V-0 flammability.

While squirrels represent over 85 percent of the animal related outages, VEC has recently seen an increase in bird related outages due to an increase in osprey population around Lake Champlain. Unfortunately, three-phase, forty-five-foot poles with cross-arms make excellent nesting spots for osprey. Outages on these locations generally affect many members due to a high density of members in that area. VEC established an avian protection plan that involves patrolling three phase main lines and removing sticks before they turn into nests identified on these (late April through October). If the osprey comes back to same location, VEC sets a pole and platform away from our distribution line to allow the osprey to build their nest while not affecting the power system.

7.4.6 Pole Inspections

VEC performs a pole inspection and treatment program on all distribution poles over a 10-year cycle and once every ten years for transmission poles. These timelines are in line with RUS Bulletin 1730B-121. VEC's program consists of ground line inspection, treatment 18 inches below ground level and internally (using Mitci-Fume, a widely used fumigant), visual inspection of above ground condition and other maintenance work such as replacing missing guy guards and pole numbers. VEC's joint ownership agreement with Consolidated Communications identifies pole installation ("set") and maintenance areas. VEC inspects all its sole owned distribution poles across the system and the joint owned poles with Consolidated in VEC's maintenance area. Consolidated Communications is responsible for pole inspection of joint owned poles in its maintenance area.

Data from the inspection is stored in VEC's GIS system and reports are generated each week from the pole inspectors. These reports are sent to VEC's engineering team for review, a work order is opened for pole replacements and the projects are designed and readied for construction.

VEC replaces any rejected poles within twelve months of the pole inspection. Over VEC's 10-year distribution pole inspection (2010-2021), VEC has rejected on average 2.68 percent of its inspected poles. The average age of rejected poles is 58 years old (manufactured in 1963).

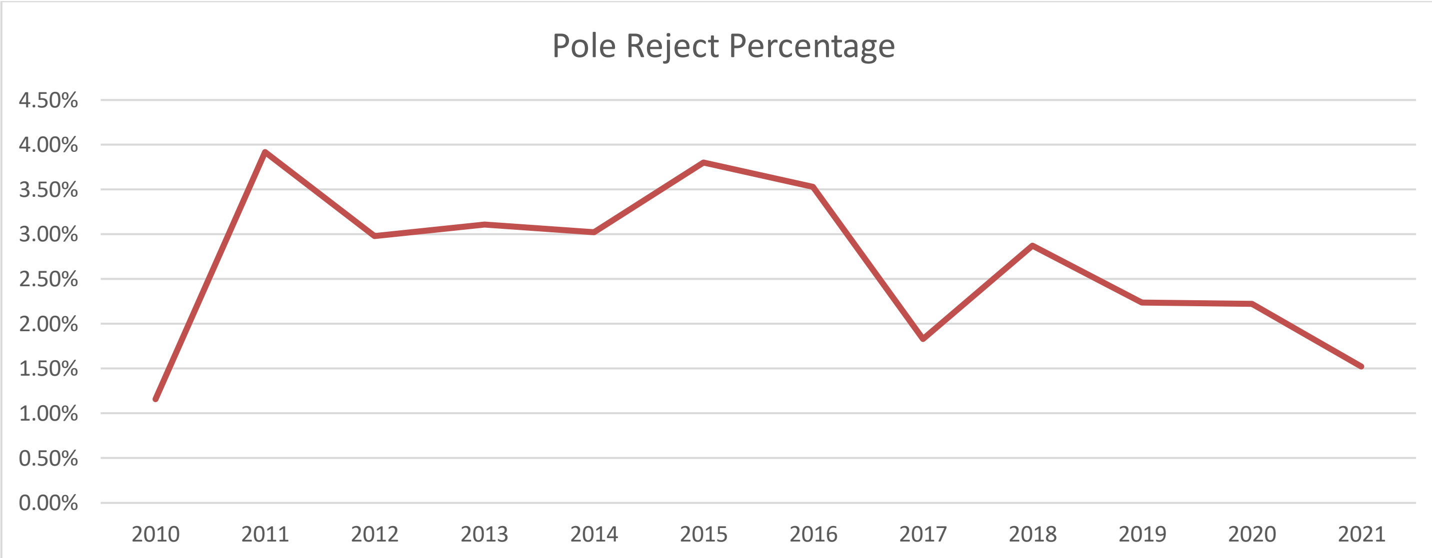


Figure 7.4.6.A Distribution pole reject percentage

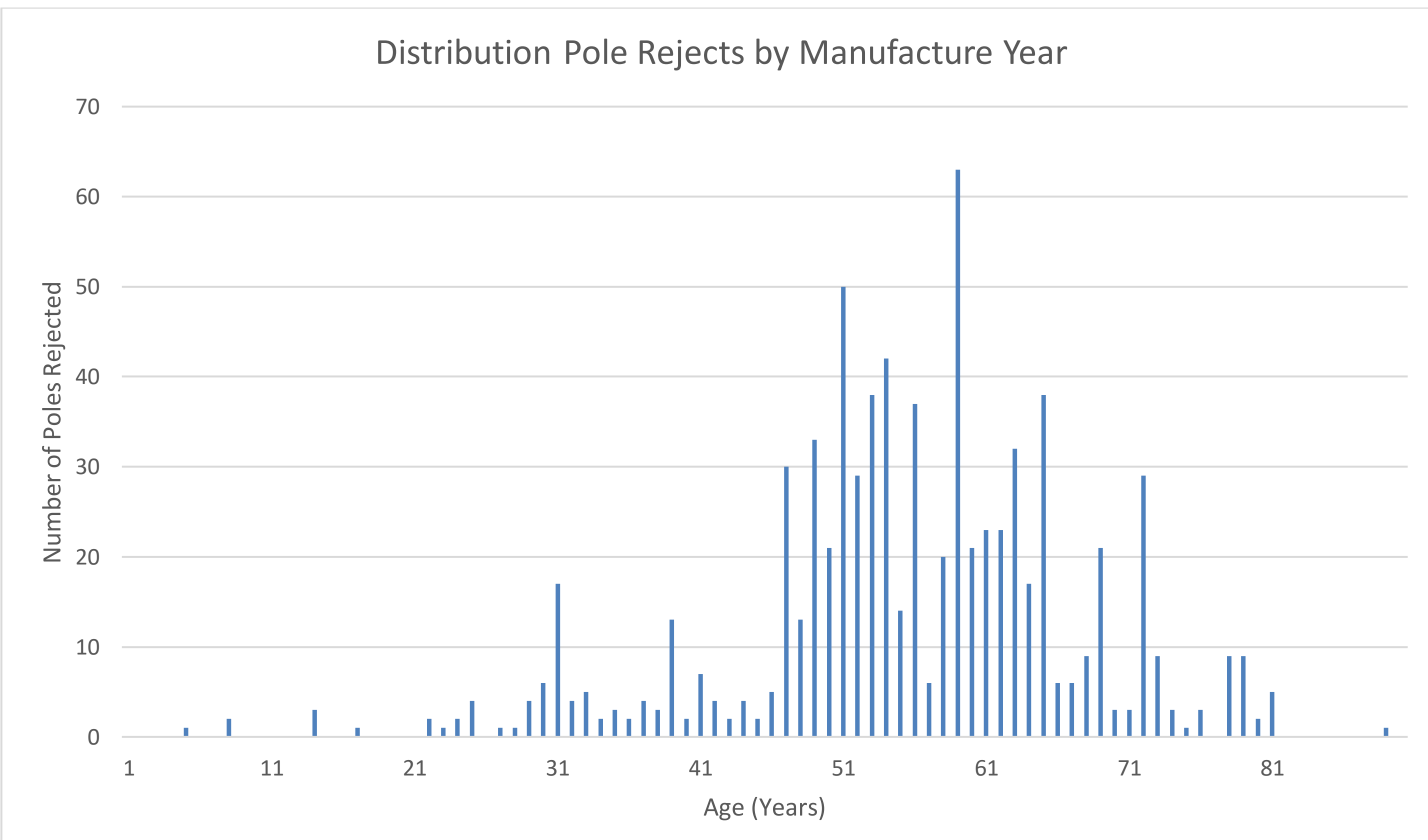


Figure 7.4.6.B Distribution pole rejects by manufacture year

The chart above indicates that poles that are younger than the average rejected age poles (58 years) are less likely to be rejected. The poles at or older than the average reject age is more likely to be rejected as they are more likely to have not been maintained since they were installed. VEC completed its first pole inspection and treatment cycle in 2021.

While most pole rejections identified during the pole inspection program are because of problems at the ground line, VEC continues to have some additional issues at the top of poles due to decay from water ingress and subsequent loosening of pole top hardware. VEC recently updated its pole installation standard to include an Osmose "Pole Topper" or cap on all new pole installations. This pole topper functions very similar to a roof on a house and protects the pole top from moisture ingress, thus preventing future pole top degradation.

7.4.7 Worst Performing Circuits

VEC breaks down its reliability data into substation circuits for this report. VEC rates its top ten worst performers by prioritizing the number of outage events first and then customer hours out. Engineering reviews these worst performers based on type and location of the outages. VEC provided a list of worst performers based on a five-year average (2017-2021) but utilizes the 2021 data to develop projects and mitigate these outages.

Worst Performers Average (2017-2021)

The chart below displays the average worst performing circuits from 2017-2021

Rank	Circuit Name	OUTAGES	HOURS
1	Burton Hill 3A	53	3,211
2	Hinesburg 3A	49	4,328
3	Island Pond 4A	43	4,888
4	Cambridge 1A	37	3,399
5	Johnson 3A	22	3,703
6	Irasburg 3A	38	2,496
7	North Troy 3A	33	2,694
8	Hinesburg 1A	34	3,839
9	Irasburg 1A	37	2,648
10	West Charleston 1A	36	3,613

Table 7.4.7.A 2017-2021 average worst performing circuits

Worst Performers in 2021

The chart below displays the worst performing circuits in 2021.

Rank	Circuit Name	OUTAGES	HOURS
1	West Charleston 2A	45	14,449
2	Island Pond 4A	43	14,219
3	West Charleston 1A	44	12,319
4	West Charleston 3A	25	12,201
5	North Troy 3A	52	5,514
6	Burton Hill 3A	52	5,390
7	Hinesburg 1A	36	6,491
8	Irasburg 1A	47	4,936
9	West Charleston 4B	19	11,218
10	Cambridge 1A	48	4,250

Table 7.4.7.B 2021 worst performing circuits

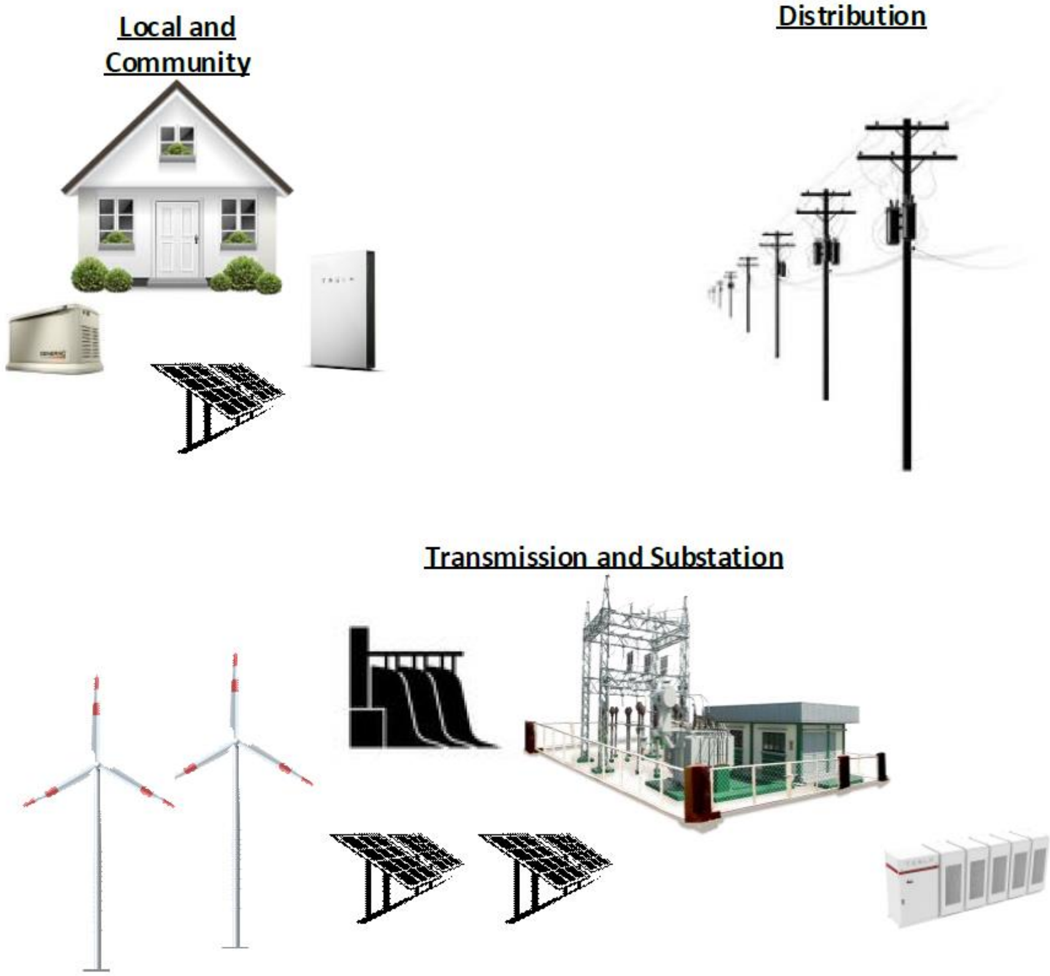
In 2021, VEC invested over $500,000 in capital improvements on its 2020 worst performing circuits. These capital improvements included the installation of new animal and arrestor guards, new fused cutouts on side taps, and several line relocations. VEC invested approximately $2.8 million in routine vegetation maintenance and hazard tree removal over approximately 170 miles of line within the worst performing circuits in 2020 and 2021. VEC prioritizes reliability improvement projects, which generally include reconductoring with tree wire, adding mid-span poles, additional feeder protection, and line relocations, for the circuits identified on the worst performing list.

7.4.8 Review of SAIDI > 1 Hour

In 2019, VEC began reviewing all outages with a SAIDI (System Average Interruption Duration Index) value of greater than 1 hour. These SAIDI reviews include an analysis of operating procedures, lineworker efficiency, system protection, and potential system upgrades to increase operational effectiveness moving forward and hopefully reduce the likelihood of future outages.

7.5 Investing in a Resiliency

As discussed earlier in this section, weather related outages will continue to impact VEC's electric grid. VEC continues to prioritize investments that can reduce the duration and severity of these events or, in some cases, eliminate the impacts significantly. There is no one size fits all solution to resiliency, but rather each option is a tool in the toolbox of keeping the lights on. We have classified resiliency into three sections:



1. **Local and Community –** This includes our members' homes, businesses and communities. In general, our strategy involves incentivizing and encouraging the installation of household batteries and standby generators to eliminate outages.
2. **Distribution–** This includes our primary overhead and underground lines as well as any equipment associated with them. Our strategy focuses on strategic undergrounding, reconductoring and sensors.
3. **Substation and Transmission –** This includes our substations, subtransmission lines, and any bulk transmission assets. We focus on feeder backup, motor operated switches. In addition, our strategy here is to explore long duration transmission storage, adequate planning, and expanding our capacity to connect to Hydro Quebec.

7.5.1 Our Resiliency Strategy and Priorities

In regards to resiliency our strategy and priories are as follows:

1. **Invest in strategic line relocations and undergrounding** – Over 60 percent of VEC's lines are "off-road" and difficult to access with appropriate large equipment for restoration activities, often extending outages. Additionally, VEC has over 200 miles of #6 Steel and 8D Amerductor wire many of which correspond to the same off-road line locations. This type of wire is extremely brittle and requires an outage to conduct any work on the wire, whether it is due to a broken wire. We plan to replace all our #6 Steel and 8D Amerductor wire by 2030 and relocate as much line as possible.

2. **Expanding our capacity to connect to HQ during emergencies -** VEC has four interconnections with HQ that could be used during a capacity deficiency scenario, if one was declared, by ISONE England. Utilizing and expanding the substations connected through these interconnections has the potential for significant positive impacts to VEC and the entire state of Vermont during a capacity deficiency (e.g., reduce or eliminate the necessity for "rolling blackouts" to meet a load reduction declaration). HQ provides sustainable reliable, renewable, base load that is not part of the ISONE grid.

3. **Explore resiliency as a service** - The financial ramifications from outages include operating costs and as well as societal financial impact. We plan to explore how we can incentivize the purchase of a standby generator or home battery to eliminate outages at the home altogether to improve resiliency and reduce financial impacts to the home or business.

4. **Expand feeder backup and invest in motor operated switches -** Around 57% of the members mentioned above who are on radial subtransmission lines (around 28% percent of VEC's total membership) are also served from a substation that does not have full feeder backup. Feeder backup enhances reliability and reduces cost by adding greater flexibility to the system.

5. **Educate, determine funding, and implement Microgrid pilots -** Microgrids have the potential to mitigate long-term outages from extreme weather events, provide grid services, and improve reliability. Microgrids improve resilience by disconnecting from the main grid during an outage and using local resources, including storage, small generators, and/or renewables to keep power flowing to communities. VEC is evaluating the types of microgrids, where microgrids might be a net benefit to the grid in our service territory

6. **Utilize FEMA Hazard Mitigation Funding (HMF) to speed up these investments-** FEMA HMF This assistance is unique to municipalities and non-for-profit cooperatives such as VEC. This funding allows VEC to benefit from additional capital investment to achieve its goals of improving resiliency across the priority areas described above. While the additional funding is valuable, it does require resources and time to build/monitor the grants, and implement additional projects in a timely manner. But, VEC finds this effort worthwhile. Since 2015, VEC has received almost $3.5 million from FEMA for Hazard mitigation projects and the projects that have been completed have had dramatic decreases in outage events, in some cases eliminated altogether.

We break down these strategies and more in the sections below.

7.5.2 Local and Community Resiliency

Local and Community resiliency is focused our members' homes, businesses and communities. Unfortunately, given the scale and scope of our needed investments and routine maintenance our members will continue to see outages. Even in the most reliable areas of the country, customers still see periodic outages, especially during large events. VEC's strategy is to identify ways to eliminate outages for our members all together and through standby generators, microgrid and home batteries we hope to accomplish this.

Home Batteries

As we discussed in Section 4 – Energy Transformation, the incentives VEC provides can help bring down the cost of a home battery system. Home battery systems have the additional of impact of providing resiliency benefits to members. A typical Tesla Powerwall has around 5kW 13kWH

Resiliency as a Service

VEC has identified the cost that an outage has to its membership both from operating impacts as well as a societal cost. We plant to explore how we can incentivize the purchase of a standby generator or home battery. More than 3,000 of VEC's members already have standby generators in many cases eliminating outages all together. In our most recent survey almost 50% of members had either a standby or portable generator.

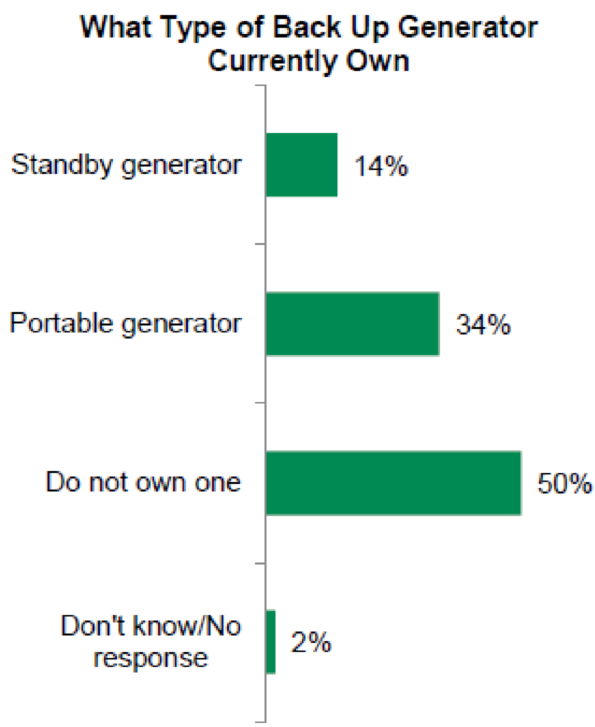


Figure 7.5.2.A 2022-member survey data on standby and portable generator ownership

VEC is also in the process of mapping these facilities to better understand how to manage these resources.

Secondary Underground on New Service

Over 70% of line extensions installed in VEC's service territory in 2021 were underground. The percentages are even higher for new developments. In addition, the towns of Hinesburg, Williston and South Hero require that any new secondary installation must be underground.

Underground over the lifetime of the asset is both more reliable and less costly than overhead in the case of a brand-new installation. This is discussed further in the Underground section. VEC is exploring ways to incentivize more underground construction to reduce outages in the future.

Microgrids

The U.S. Department of Energy (DOE) defines a microgrid as ''a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode." Microgrids have the potential to mitigate long-term outages from extreme weather events, provide grid services, and improve reliability.

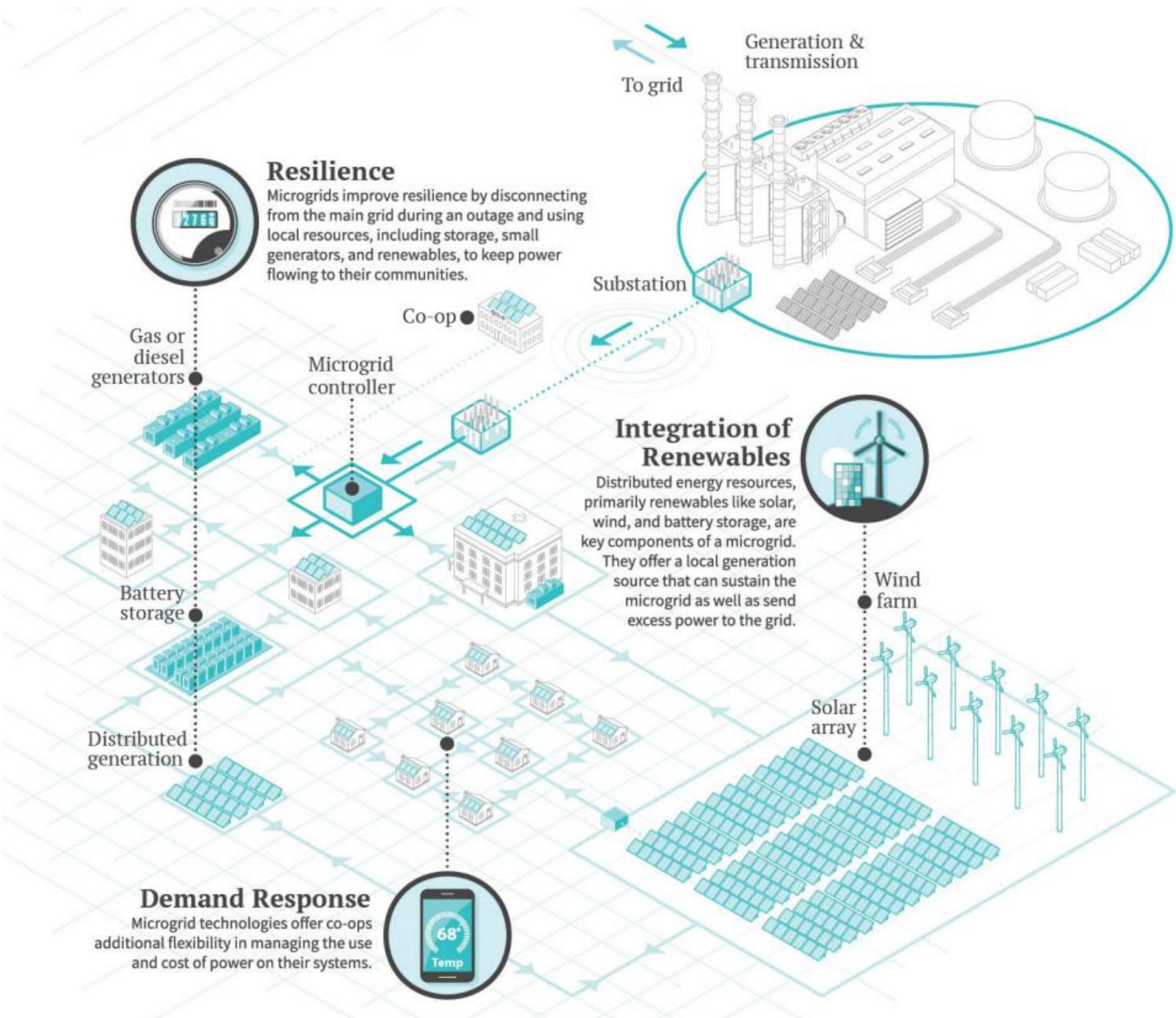


Figure 7.5.2.A NRECA Microgrid visual overview

VEC has made a strategic initiative to develop a plan and implement microgrids through its service territory. VEC's plan comes in two primary strategies:

Responding to Community's Needs

VEC has had several communities reach out to us in regards to Microgrid and resiliency projects.

Systematic Approach

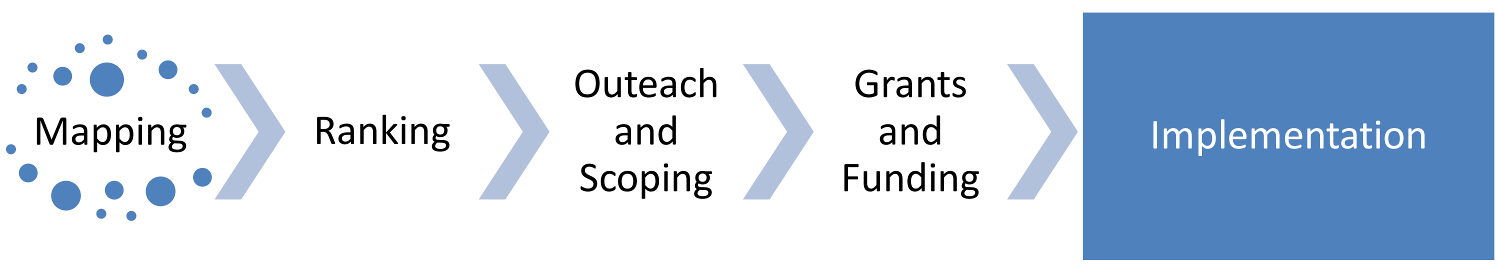
VEC is holistically mapping and ranking all microgrid opportunities on its system. This will enable us to determine which locations make the most sense to prioritize, engage with those communities and implement a project.

Responding to Community's Needs

As communities reach out to VEC, we educate them about what the project could entail along with the potential revenue streams. We then size the project appropriately, work to identify funding whether grants or other investments/incentives, and manage the project to completion.

Systematic Approach

Our systematic approach includes the following components:



Mapping

To identify locations suitable for resiliency effort such as microgrids VEC has mapped the following vulnerabilities:

- Social – Social vulnerabilities identify low income populations, members with high energy burdens, or other health burdens. In addition to government census data, VEC is using Efficiency Vermont's energy burden report and the Climate and Economic Justice Screening Tool put together by the Federal Government.
- Natural Hazards – This vulnerability includes locations that are impacted by flooding, high winds, or other weather events. We utilize charts and data in the Northview Weather Extreme Weather and Climate Change in Vermont: Implications for VEC's Asset and Storm Planning report
- Critical Infrastructure – Critical infrastructure includes facilities like hospitals, schools, water treatment plants, fire and police stations, and emergency shelters. We are also in the process of mapping grocery stores and hardware stores as those become more critical during long duration events.
- System – This vulnerability category represents locations on VEC's system that are have seen long duration or frequent outages. VEC worked with NorthView Weather to develop a GIS based tools that displays which members are more impacted by outages. In addition, using our EnergyHub cost of service tool, we also mapped the top 100 members who have impacted us the most during the monthly Vermont peaks and yearly ISONE peaks.

Once mapped, proposed locations are added to a database.

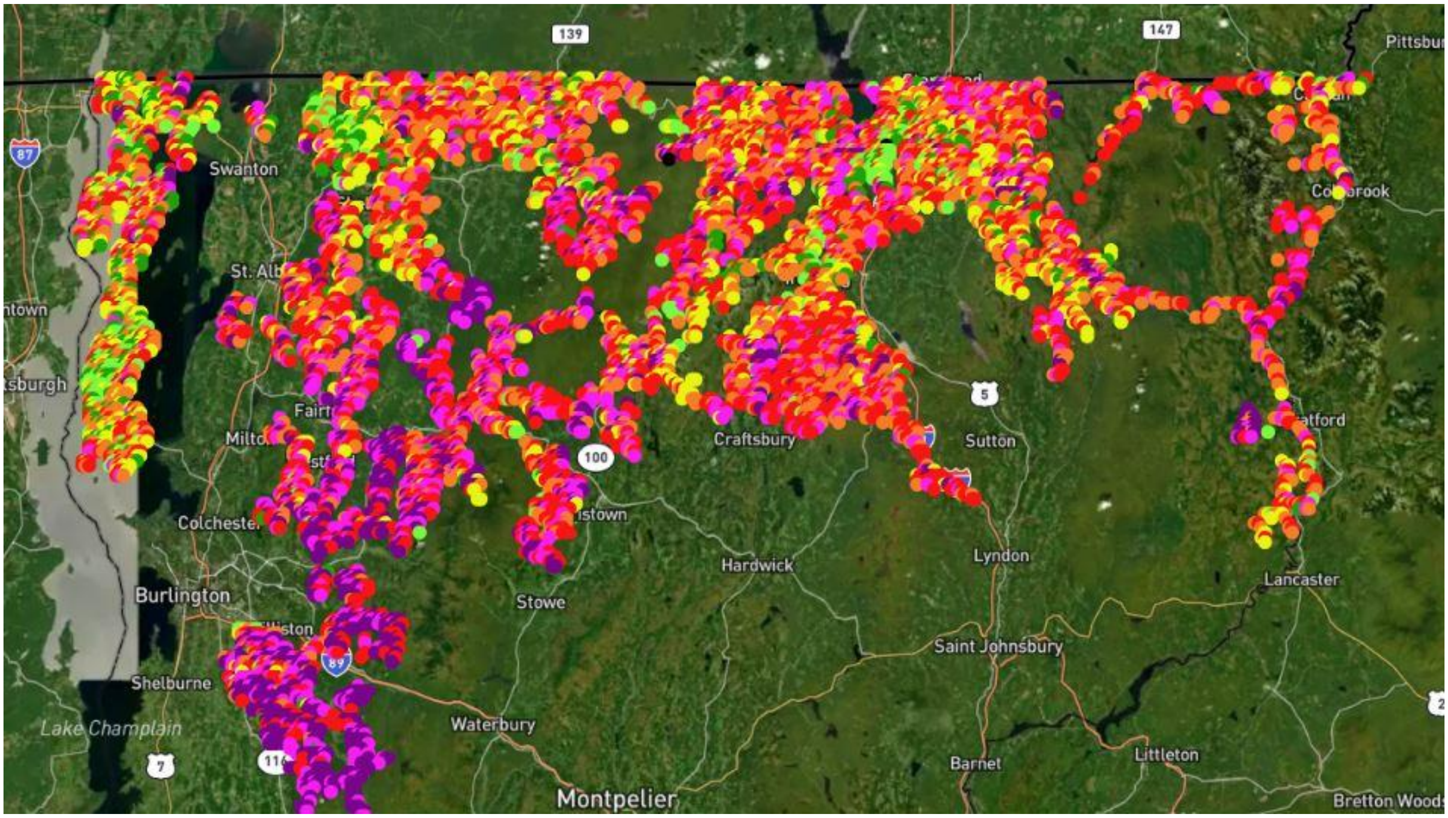


Figure 7.5.2.B VEC outage locations 2011 to 2021. Darker colors represent higher numbers of outages

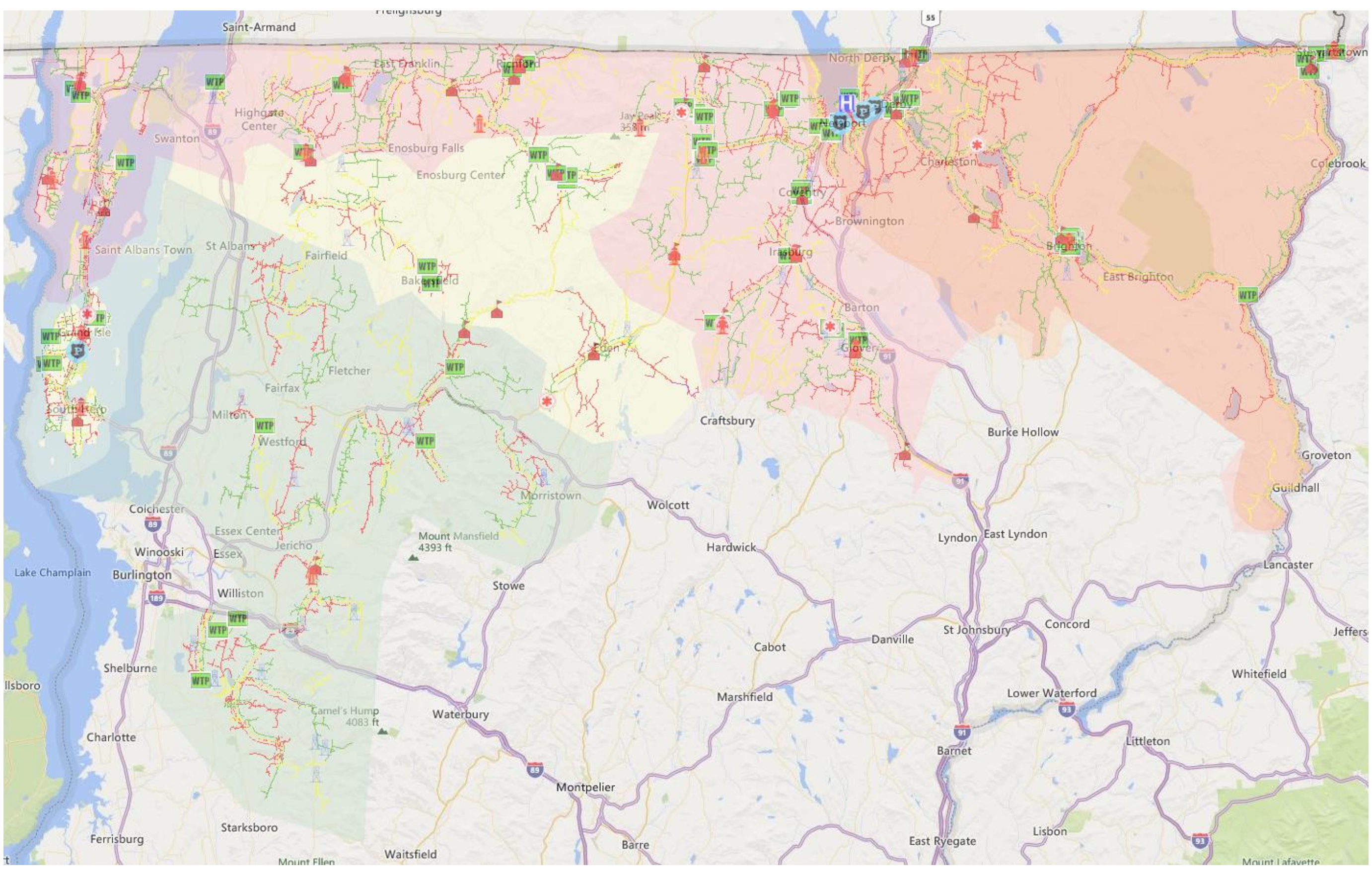


Figure 7.5.2.C VEC mapping of SHEI and critical facilities

Ranking

Our database of potential microgrid projects is then assessed based on a multitude of criteria. This includes which locations are in the SHEI, have highest energy burdens, multiple critical facilities, and are most susceptible to climate impacts and outages.

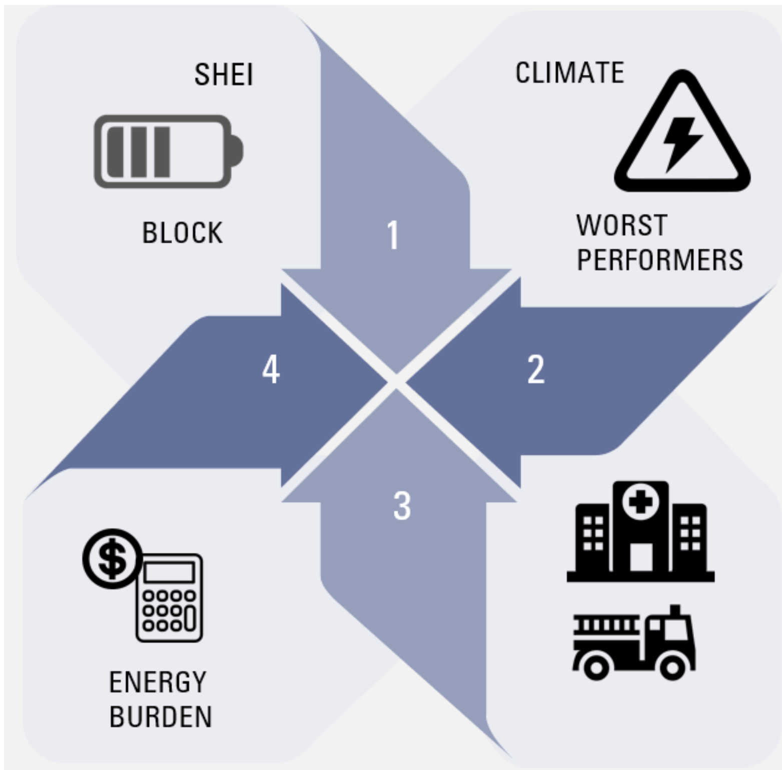


Figure 7.5.2.D Ranking of potential microgrid locations

Community Engagement

Engaging with our communities and the members that are impacted is critical to ensuring that these projects are a success. In addition to our communities we also work with our regulators, industry groups such as NRECA, and other cooperatives throughout the country. This space is still quite new so there is a lot of learning for VEC on any potential project.

Project Scoping

To size the project appropriately, we will:

- Work with the community to Identify any critical loads/buildings.
- Review the microgrid location and identify what circuits/phases the project is on. Ideally the proposed project does not have more than a couple of disconnecting/connecting points.
- Use GridSolver and our MDM to determine average and max loads for the project and any current or planned generation.

- Take into consideration any existing battery or fossil resources (backup generators) that may enable a longer duration response.
- Identify the communication methodology and visibility requirements to ensure that the project connects and disconnects seamlessly.

Funding

In most cases the storage assets and generation that enable the microgrid will be owned and maintained by the community. VEC typically will utilize these resources for peak shaving in addition to managing the interconnection of the Microgrid.

The recent infrastructure bill has several carveouts for microgrids and there is also funding available through FEMA Hazard Mitigation projects which are discussed in more detail later in this section.

Implementation

Once we have identified funding and finalized a project scope, we will manage the interconnection of the project while the community procures the energy storage and renewable generation resource (e.g., solar, wind, etc.). In general, the interconnection will include additional VEC switches to help island the project and ensure the rest of our members are not negatively impacted.

7.5.3 Distribution Resiliency

Distribution Resiliency includes our primary overhead and underground lines as well as any equipment associated with them. We are focused on moving difficult to access lines, reconductoring conditionally poor infrastructure and undergrounding where cost affective/applicable. While we expect to continue to see outages our hope is that we have easy to access facilities that are less susceptible to weather related events.

Strategic Line Relocations

Almost 60 percent of VEC's distribution lines traverse cross-country, not roadside locations. Much of VEC's system was constructed in the early to mid-1900's, when Vermont was mostly pastured or open land and utility lines were constructed based on the shortest distance between two points to save on costs.

Bucket trucks are not able to easily access these cross-country lines and as a result, there is an increase in the cost of line maintenance and outage restoration duration. Also, the poles on these cross-country lines are older and smaller class, increasing the likelihood that they cannot be climbed safely. In addition to climbing, VEC also relies on off-road vehicles such as ATV's and tracked bucket trucks shown below

Table 7.5.3.A   VEC line crews utilizing a tracked bucket truck to access an off-road pole

While it is unrealistic to move all VEC's off-road lines to the road, there are many outage-prone, difficult to access, and high maintenance cost (vegetation maintenance) locations where the cost and time to relocate the line are justified. VEC gives higher priority to lines that are currently inaccessible or present environmental challenges (wetlands or washout). However, these projects are dependent on the acquisition of easements and permits required to move lines to the road. In many cases, there are significant delays for these projects due to difficulty obtaining easements from members for a variety of reasons (e.g., tree removal or pruning, aesthetics, access for outages and maintenance, etc.). In the event of easement issues, VEC may have to redesign the project or delay the project indefinitely.

When a VEC targets a project for relocation, VEC performs the following coordination with stakeholders:

1. VEC will contact landowners affected by the relocation during the easement procurement process. This includes any locations where VEC will need to perform routine vegetation maintenance for poles and anchors.
2. If there are attachees on the existing line or the line targeted for relocation, VEC will contact the appropriate attachee a minimum of one year in advance of project construction.
3. VEC will contact State, Towns, and Municipalities when a relocation occurs within city, town, or state right-of-way to acquire permits.
4. VEC will contact Act 250 District Coordinators or the Vermont Agency of Natural Resources for required permits such as Act 250 or wetland permits.

If relocation is not feasible, VEC will attempt to improve the line's reliability through more robust construction such as the use of spacer cable and covered tree wire for conductors, an increase in right of way width, or more frequent right of way trimming.

Undergrounding

VEC has found that undergrounding can greatly expedite and enhance the right-of-way acquisition process.

In VEC's service territory, on average a 12.47 kV underground distribution line initial construction costs approximately two times the cost of an overhead line, mainly due to the increased labor, increased indirect costs (e.g., conduit, vaults, drainage systems, etc.), and specialized equipment used for cable pulling. However, VEC has seen costs of overhead construction increase over the last ten years reducing the cost difference making going underground a more viable and cost competitive alternative.

When looking at yearly and lifetime maintenance costs, overhead construction is often more than four times the lifetime cost of underground primarily due to vegetation management costs and a higher susceptibility to outages.

	Per Mile Yearly Maintenance Cost	Lifetime Cost (50 Years)
Single Phase Overhead	$ 5,071	$253,550
Single Phase Underground	$1,222	$61,100

Table 7.5.3.B Yearly and lifetime cost of underground conductor

VEC calculates the annual maintenance costs using the following:

- Property tax costs per mile for underground and overhead lines.
- An average of vegetation management costs per mile. This includes all internal and external contract crews required to maintain the Rights-of-Way (ROW) corridors for VEC.
- An average of overhead line maintenance costs per mile. This includes line worker time spent on outage restoration and routine inspection of overhead and underground lines.

Using the numbers above and assuming new construction (conduit, jacketed EPR cable, burial, and installation) if the initial cost is less than 2.1 times the cost of overhead construction, then underground would be best option from an overall cost standpoint. There are other factors to consider, especially when relocating lines from overhead to underground. These factors include presences of ledge, number of existing overhead services, environmental constraints such as streams or wetlands, and future load growth. All these factors will increase the cost of underground and in many cases to a point where it is no longer feasible to move a line underground.

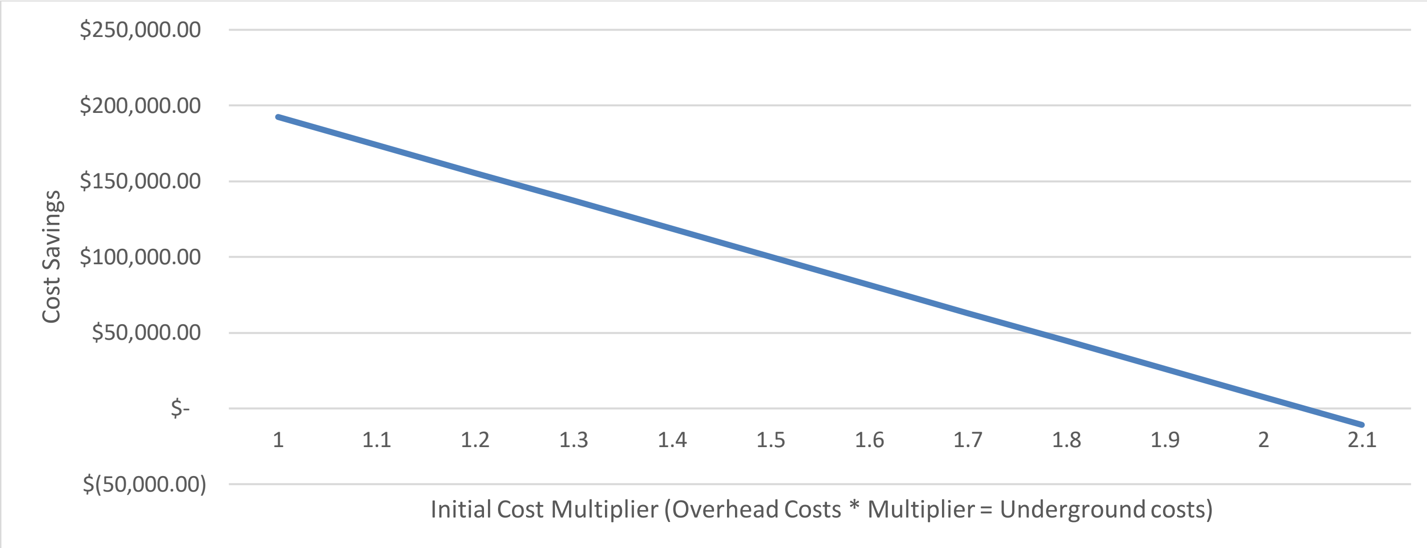


Figure 7.5.3.C Overhead to Underground Cost Comparison (50 Year Asset Life) for single phase

<u>Reliability of Underground Conductor</u>

Undergrounded systems offer fewer outages than an exposed overhead line. However, when outages do occur (especially during frozen ground conditions) the outage is generally three to four times longer than a similar overhead outage. The figure below compares our outage experience for overhead and underground lines. It shows that overhead lines experiences outages six times more frequently than underground lines.

	Underground	Overhead
# of outages (2012-2018)	211	10,406
Miles of line	303	2,438
Outages per mile per year	0.10	0.61

Table 7.5.3.D Reliability of underground conductor

The graph below displays outage durations for all overhead and underground outages from 2012 to 2018.

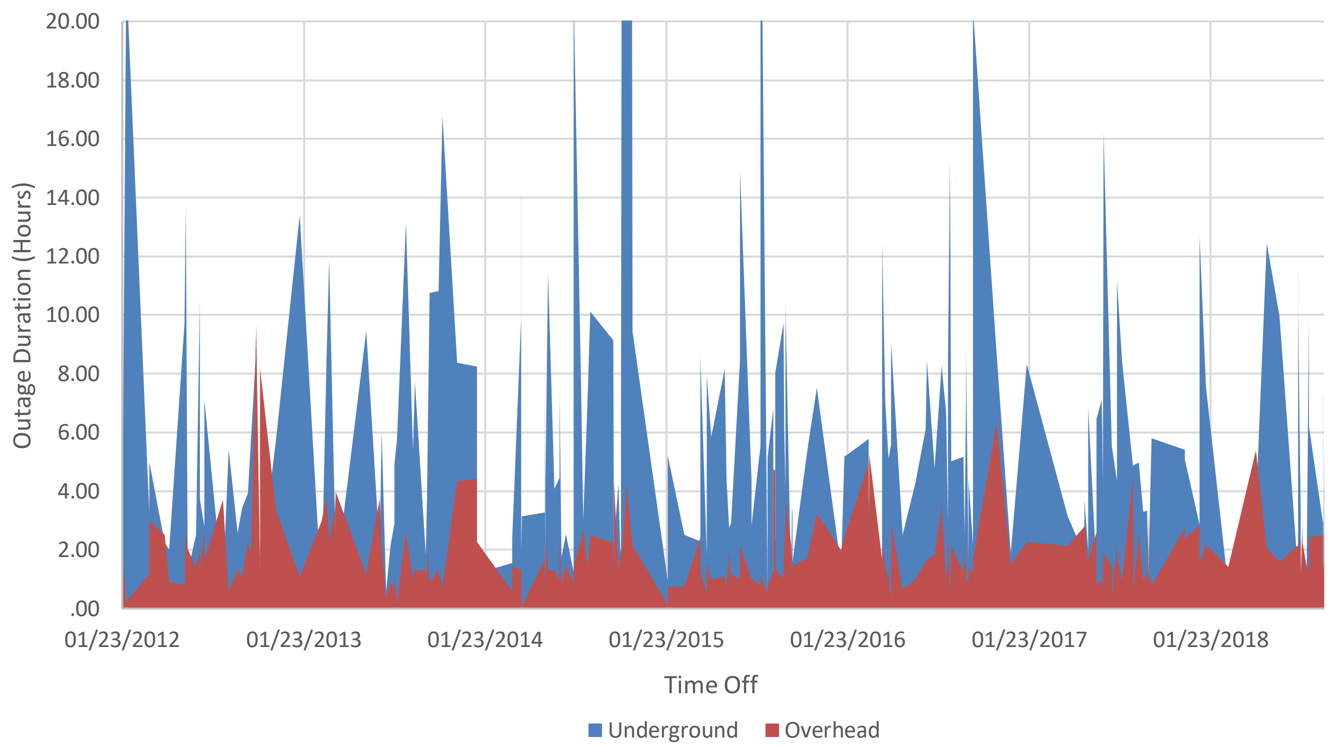


Figure 7.5.3.E Underground versus overhead outage duration (2012-2018 data)

On average it took about three to four times as long to restore outages for underground lines (approximately seven hours) versus overhead lines (approximately two hours). Direct buried underground lines take particularly long to restore because new conductor cannot be pulled into existing conduit. As a result, since all new VEC and member installed underground are required to have conduit, a new trench and conduit needs to be installed before the new line can be pulled and terminated.

VEC anticipates that it will continue to increase the number of underground line miles installed annually.

Covered conductor

The majority (86 percent) of VEC's distribution conductor is bare and the remaining 14 percent is covered conductor (often referred to as "tree wire"). VEC installs covered conductor in areas where line relocation is not feasible and in locations of likely exposure to tree-related outages. Contact with fallen or wind-driven trees and vegetation not only provides a path to earth (ground) and between conductors, but can damage bare conductors resulting from arcing and sparking. VEC has seen that covered conductor can prevent these types of outages due to the benefit of insulation on the conductor.

VEC uses three types of overhead conductor on its system: bare conductor, covered conductor ("tree wire"), and spacer cable.

Figure 7.5.3.I Bare conductor

Figure 7.5.3.J Covered conductor ("tree wire")

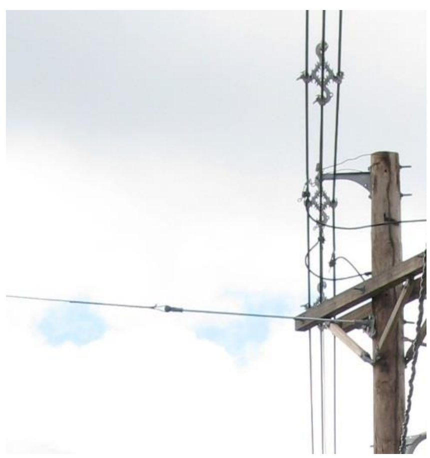


Figure 7.5.3.K Hendrix spacer cable

In general, covered conductor adds approximately 58 percent to material costs (because it is more expensive and requires shorter span lengths – e.g., more poles due to increased weight) and 13 percent to the total project cost. However, VEC finds that covered conductor and spacer cable can improve reliability and provide flexibility in space constrained areas.

VEC expects to continue reconductoring areas with outage concerns with covered conductor. The four-year average for projects that utilize "tree wire" has been around 36 percent (6.6 conductor miles annually).

Sensors and fault finders

Fault indicators provide a cost-effective visual indication of faults on the power system. They help to identify fault locations and to reduce outage duration and restoration costs. VEC utilizes Schweitzer Engineering Laboratories (SEL) AutoRanger fault indicators with approximately 300 devices installed on its system. In general, VEC installs fault indicators where power lines cross the road in areas that are difficult to access to help identify the sections of line impacted by a fault to reduce the time for restoration.

Fault indicators come in varying types but the majority last only three to five years depending on how frequently they operate. VEC's past practice was to run these devices until failure, and many of its initial installations (between 2008 and 2012) are no longer functioning. VEC purchased over 150 new devices in 2017 to replace the devices that are no longer functioning. In addition, a VEC implemented a comprehensive maintenance plan to check these devices periodically to ensure proper operation. VEC enters each location into its GIS mapping system with the date installed.

VEC is also exploring the use of SCADA connected fault indicators to help further reduce the time it takes to find an outage both in the field and through its OMS system.

Construction Practices and Solutions

One of the many challenges VEC faces on its distribution system is prior construction practices that are no longer adequate. Wet snow events can cause additional conductor sag and creep or stretching over time, which results in conductors contacting one another. The timing of these "snow unloading" events can lead to long duration outages for VEC members with limited or no system damage. There are several causes and corresponding solutions to these challenges.

Conductor Tension

As conductor ages and wears under tension, it begins to cause creep or stretching of the conductor. This normal creep or additional sag can increase with heavy wet snow events or hard tree contacts and if the conductor is not re-tensioned, there is an increased likelihood of an outage if the primary wire sags into the neutral wire. In some cases, particularly older conductors such as 6A, 6 Steel or 8D, it may not be possible to re-tension the conductor and VEC may need to replace it.

Long Conductor Spans

Some of these challenges are a result of long conductor spans (conductor distance between two poles). On average, VEC has a span length of 234 feet; however, 7,419 spans out of 99,021 (7.5 percent) are greater than 350 feet. These longer spans are needed to cross rivers, wetlands, gullies, highways, etc. In some cases, the conductor in these long spans has stretched due to snow and ice loading over the years and becomes more prone to causing outages during weather events.

This 598-foot span in Richmond is a good example of long conductor spans:

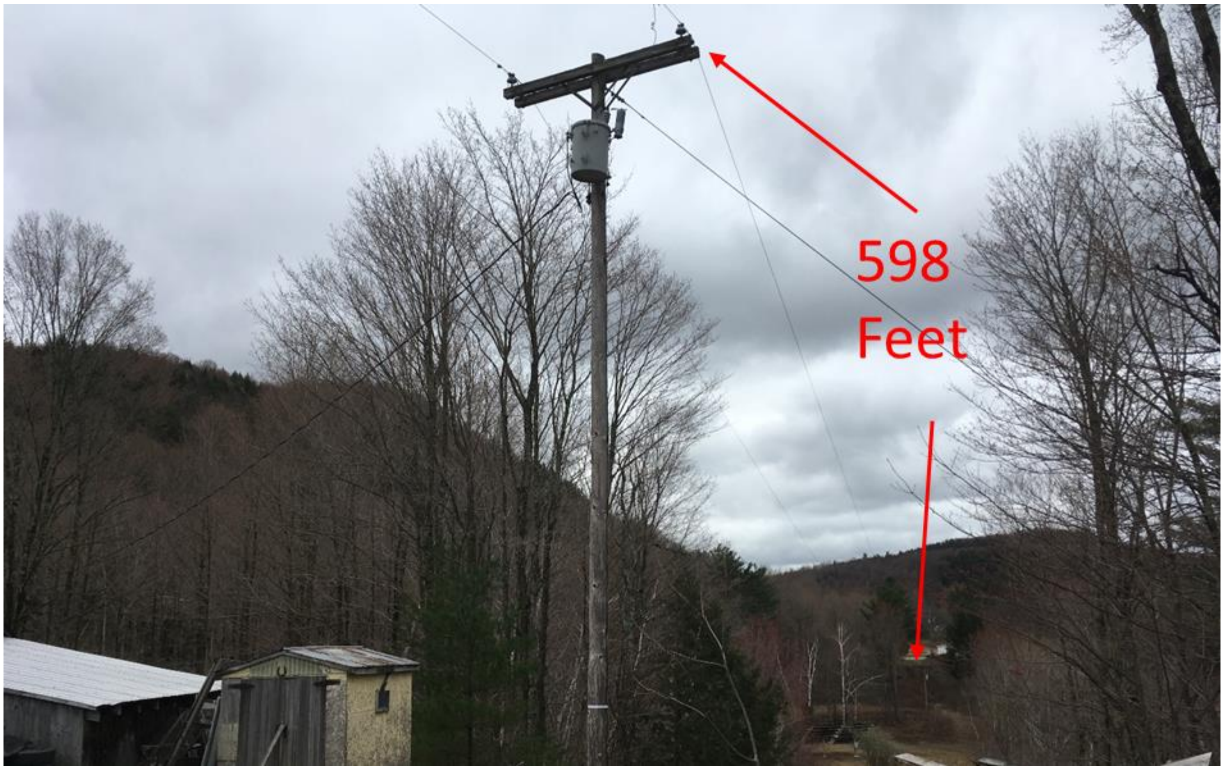


Figure 7.5.3.L 598-foot span in Richmond

Additional or mid-span poles could be installed where possible to mitigate these issues.

FEMA Hazard Mitigation Funding

The Federal Emergency Management Agency (FEMA) has two types of hazard mitigation grants: section 404 – Hazard Mitigation Grant Program and section 406 – Public Assistance Program. As a not-for-profit electric cooperative, VEC has an opportunity to qualify for both grant opportunities. FEMA designs these grants to cover costs for restoration and mitigation projects that make the system affected by an event more resilient, sometimes called "hardening."

This assistance allows VEC to benefit from additional capital funding to achieve its goals of improving reliability via reconductoring with "tree wire," moving lines to the road, and feeder backup ("tie lines). While the additional funding is valuable, it does require VEC resources and time to build the grants and monitor them. But VEC finds this effort worthwhile. Since 2015, VEC has received almost $3.5 million from FEMA for Hazard mitigation projects.

Section 404 - Hazard Mitigation Grant Program

If a FEMA level event is declared, Section 404 funds are available to reimburse up to 75 percent of eligible resiliency projects and recovery costs with the other 25 percent coming from the requesting utility. If an event is declared, VEC generally submits three to five projects for consideration totaling around $1,000,000 in capital investment. Only those projects located in counties declared by FEMA during the event are eligible to receive hazard mitigation funding and must be on lines affected by the event to mitigate future outages.

For example, in 2015, VEC submitted its first hazard mitigation project after Winter Storm Damon (December 2014). The project relocated a difficult to access line located near Gillette Pond in Richmond. VEC removed the overhead line (that was previously on a steep bank and prone to outages) and moved underground next to the road. Since that time, this section of line has seen a significant reduction in the number of outages and is a success story for the program. Many other projects completed since 2017 have seen the same dramatic decrease in outages thanks to this program.

Section 406 – Public Assistance

In addition to Section 404, VEC applied for Section 406 – Public Assistance in 2019. FEMA does not tie these funds to a FEMA event, but are available for projects that reduce the risks of areas that may be vulnerable to an event (in VEC's case, extreme weather). The State of Vermont, in general, returns millions of dollars annually to the Federal Government due to limited applications for these funds. The applications for these types of projects are due in October and awarded in the first quarter of the following year. VEC will use the same type of prioritization process as outlined above to determine which projects have the best chance to be approved. Either type of FEMA funding for mitigation projects is additional investment in VEC's distribution system for improvement and reliability.

VEC prioritizes all capital projects utilizing its Capital Project Prioritization Process discussed in Section 7. VEC then compares these projects with which projects would reduce the largest duration and quantity of outages to members, as those are more likely to pass FEMA approval. Projects typically include line relocations from wooded rights-of-way to the road for easier access, reconductoring with tree wire, installing mid-span poles, placing wire underground, and creating new tie lines for feeder backup.

7.5.4 Substation and Transmission Resiliency

Substation resiliency includes our substations. subtransmission lines and any bulk transmission assets to ISONE based generation. As renewable penetration continues to increase and we lose base load assets, the risk of impacts to reliability increase. We focus on feeder backup, motor operated switches and utility scale storage projects. While we continue to invest in our transmission infrastructure we also see the value of reliance at the substation level as it allows us more time to respond to large scale outages.

49% (~20,000) of VEC members are fed off a radial subtransmission line and are therefore more susceptible to subtransmission level outages.

Opportunities for Feeder-Backup

Around 57% (around 28% percent of VEC's total membership) of the members mentioned above who are on radial subtransmission lines are also served from a substation that does not have full feeder backup. Feeder backup enhances reliability and reduces cost by adding greater flexibility to the system. VEC gives projects that add new ties or enhance existing ties higher priority within the capital project prioritization process especially where member counts and loads are high, increased priority is given.

VEC's system has two different systems, legacy Citizens Utilities and legacy VEC. The northern legacy Citizens Utilities system is more of a networked distribution system with significant prior investment to tie substations or circuits together. In contrast, the legacy VEC system is radial with minimal prior investment to tie substations or circuits together.

What is Feeder backup?

In the event of transmission outage or maintenance requirement, feeder backup can allow the backup of a circuit or potentially substation from another substation or feeder. In the example below, Substation #1 and Substation #2 are connected via a tie switch, which is kept normally open.

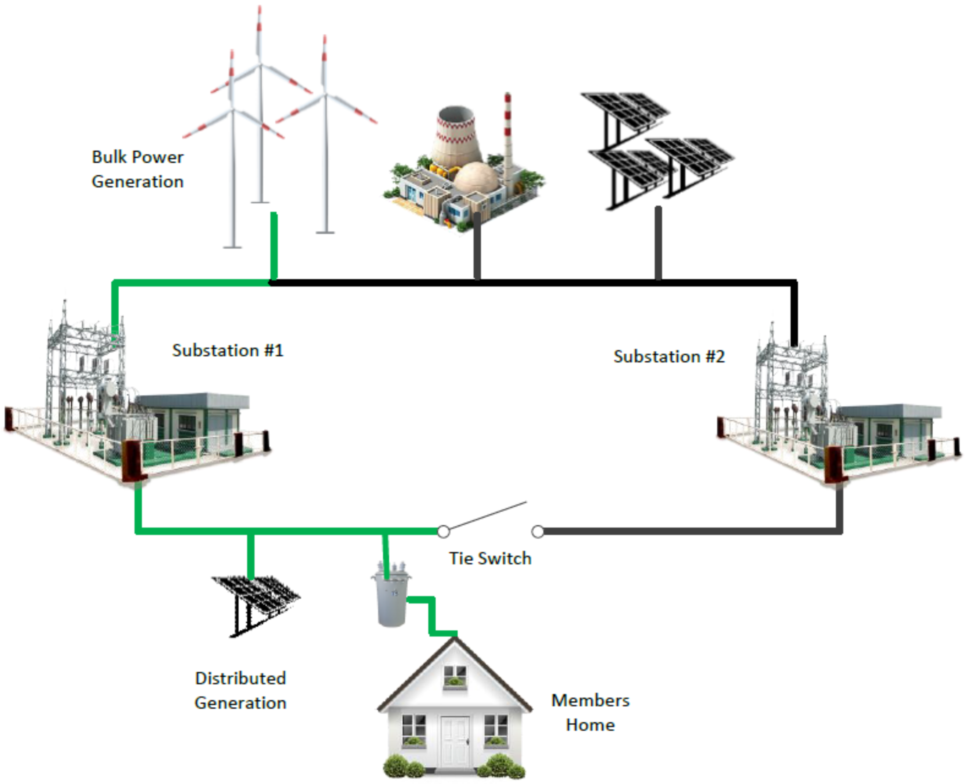


Figure 7.5.4.A   Normal configuration without feeder backup utilized

In the event of a transmission outage, this tie switch can be closed:

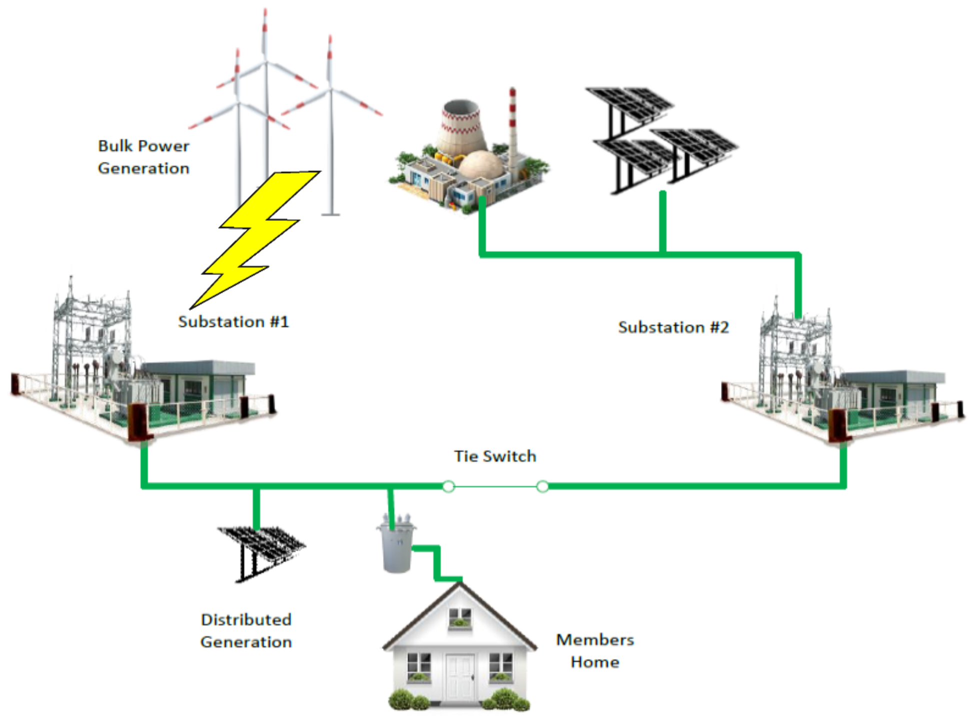


Figure 7.5.4.B Transmission outage member restoration using feeder backup

This allows the two substations to tie to together and the members located on Substation #1 to regain power. In making decisions in the future as to whether to build a feeder backup, VEC will consider the following needs:

- **Availability of a tie line** – Feeder backup is only possible in networked sections (lines connecting two circuits or substations can be tied together) of the system which are primarily located in the northern part of VEC's service territory.
- **Substation transformer capacity –** Is the transformer capacity at the substation adequate to support the additional load?
- **Distribution system capacity –** Is the wire size adequate to support the additional load?
- **Voltage of the members on the line** – The VEC system has many relatively long distribution feeders with sparse loading per mile, small conductor, and having only a single phase. In some cases, the voltage may no longer be in tolerance if another substation picks up the load due to the increased the distance of the line.
- **Distributed generation on the system --** If the feeder with a large generator is tied to and sourced from a feeder further from the source, the voltage rise can exceed the top of the acceptable voltage range.

Motor-Operated Tie Switches

To enable feeder backup, there are typically required system upgrades such as reconductoring or new tie lines. VEC considers installing motor operated SCADA controlled tie switches to these feeder backups when conditions warrant and appropriate to make switching easier and faster.

In the event of a transmission outage, SCADA and Inter Company Communications Protocol (ICCP) notify VEC System Operations. Utilizing transmission operating guides (TOGs), VEC system operators will verify if VEC can pick-up the load from another source. If another source is available, system operators will remotely close a motor operated tie switch that will allow restoration to that circuit. VEC has 28 locations where feeder backup is possible and 14 are equipped with SCADA enabled motor operated tie switches.

While SCADA is typically beneficial for transmission outages, if the fault occurs downstream of a distribution system protective device, VEC personnel would still need to patrol the line to confirm it is safe to re-energize, therefore greatly reducing the time saving benefits of SCADA. As a result, VEC does not install SCADA on all electronic distribution line reclosers and switches. VEC weighs the cost and benefits to SCADA installations on a case-by-case basis.

Subtransmission Improvements

VEC has several substations that are fed from GMP owned 34.5kV subtransmission lines. Many of these lines are long and travel through off road and wooded terrain and are prone to outages

VEC recently completed a joint project with GMP at its Cambridge substation. The VEC Cambridge substation is located between the GMP Johnson Substation B8 breaker and the VELCO East Fairfax X29 breaker. If a fault were to occur anywhere along this approximately 14-mile line, the VEC Cambridge Substation, along with 4 other VEC substations and one GMP substation are left without power until utility crews can get the line fault sectionalized, and assess and repair the damage to restore electric service.

The project added breakers to the two incoming GMP 35 kV transmission lines and VEC's radial line to its Madonna substation. This improvement in system protection automatically sectionalizes GMP's lines keeping the Cambridge and Madonna members energized if a fault exists on the GMP transmission system fed either side of the Cambridge substation. Depending on the fault location this also helped members at the other substations fed by the subtransmission line.

While this solution is not cost effective to do at every substation sectionalizing the transmission line has significant reliability benefits and VEC is actively working on another project with GMP at its jointly owned Richmond #8 substation.

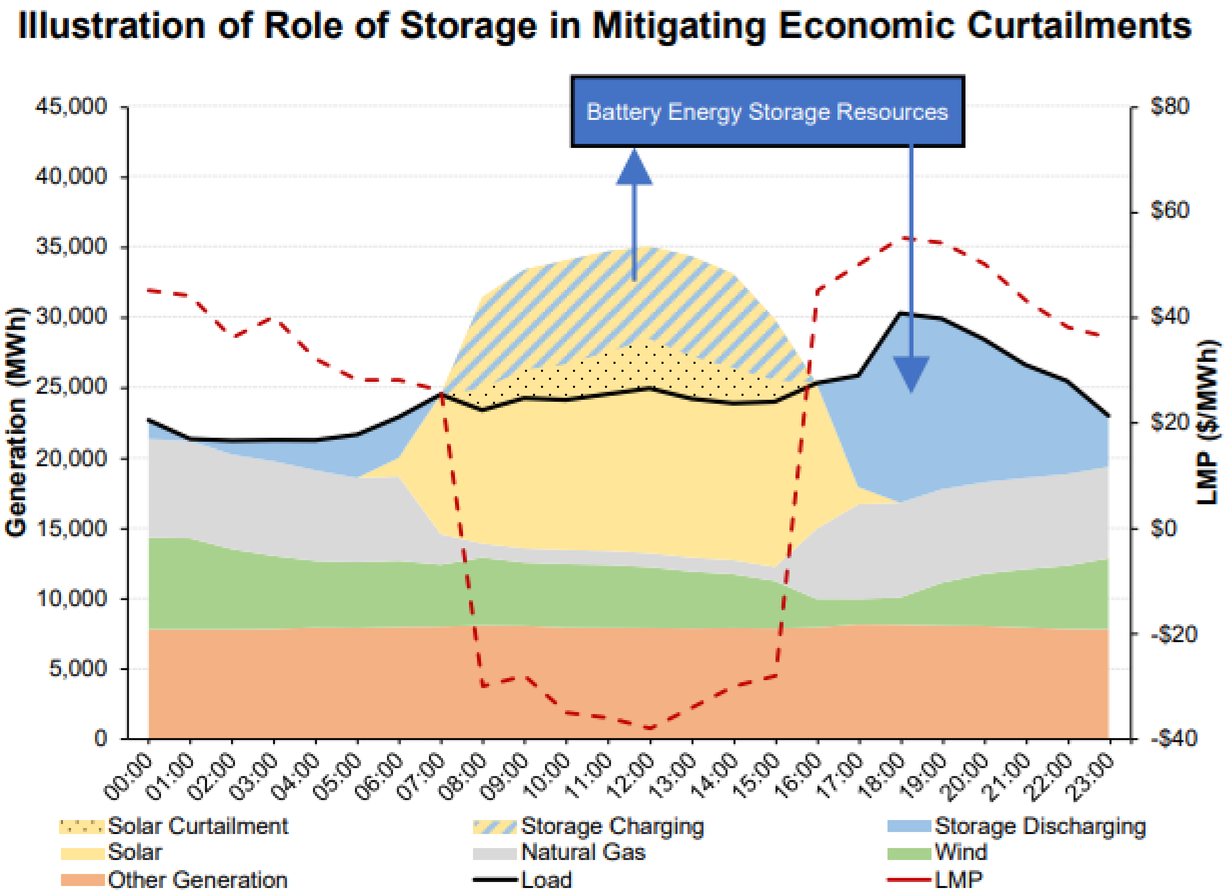
Utility Scale Battery Storage

VEC has a utility scale battery at its Hinesburg 19 substation and is planning to install batteries at other substations in its territory. While these batteries could be utilized in times of transmission level outages there are two issues with doing so:

- <u>Cost –</u> Currently VEC pays to utilize the battery for 400 hours per year to decrease our load during the Vermont monthly peaks and ISONE yearly peaks. To utilize the battery for outages we would need a new contract which would limit our developer's ability to utilize the battery in the frequency regulation market. Given the limited cost/benefit of the project we have not pursued further. Additionally, we would need additional system protection and equipment to allow the battery to feed back onto the feeder when grid power was not present.
- <u>Reliability benefit –</u> While using the battery during a transmission outage would keep the lights on at the substation we would not be able to eliminate downstream outages which are much more common. VEC has very few transmission and subtransmission outages.

Exploring Options for Transmission Level Storage

VEC is in early stages of working to identify funding and exploring technologies for long duration transmission storage. We believe that there will be a host of solutions needed to enable 100% clean energy 24/7 and long duration storage is one of those. Working with our transmission partner VELCO we hope to take advantage of federal funding opportunities to test this in our service territory. In addition to meeting the generation needs of our energy future this resource could also be used for peak shaving which could benefit all of Vermont.



https://www.ISONE.com/static-assets/documents/2022/04/npc-20220426-composite2.pdf

NEPOOL PARTICIPANTS COMMITTEE FUTURE GRID PATHWAYS

Storage can mitigate curtailments by charging during periods of overgeneration and discharging when fossil generation is on the margin. LMP price spreads provide economic incentive for batteries to shift variable renewable energy. Discharge of energy reduces emissions by displacing fossil generation with storage energy (charged using variable renewable energy)

Expanding our capacity to connect to HQ during emergencies

VEC has four interconnections with Hydro Quebec (HQ) that we can use during a capacity deficiency scenario, if one was declared, by ISONE England. This capacity deficiency scenario would most likely be the result of prolonged cold temperatures (a week or more) in Southern New England (December through February) where natural gas is diverted from electrical generation to home heating and the ability to maintain natural gas and diesel levels for electrical generation is strained or compromised.

VEC participates in the Winter Readiness Task Force, a sub-committee of the VELCO Operating Committee, comprised of several Distribution Utilities and VELCO to discuss options for meeting a voltage reduction order from ISONE England. While VEC and others are prepared to enact various Operating Procedures such as Actions During a Capacity Deficiency, Actions During an Emergency, and Voltage Reduction and Load Shed Capability (load shedding and Under Frequency Load Shedding – UFLS) that may include "rolling blackouts", VEC has the unique opportunity to shift load from ISONE England to HQ which may prevent "rolling blackouts" in VEC's territory and perhaps for the entire state.

The interconnections between VEC and HQ are broken into two blocks:

Highgate Block

This interconnection is used by several DUs and is interconnected to the Vermont gird through VELCO. 250 MW is available from HQ but only 225 MW can be used due to the capacity limitations of the converter. VEC is analyzing increasing its use of this connecting for emergency purposes by adding approximately 25 MW of load (current loads from 2021 normally served range from 10-24 MW). VEC has confirmed ISONE England will not prevent VELCO from splitting the ring bus at its Highgate substation even though it is a Blackstart Cranking Path for the McNeil generator. VELCO has also confirmed they have the capacity to put the system into this type of configuration. During the summer of 2022, VEC will need to confirm that HQ can provide capacity as they are sometime limited to 140 MW. Sometimes power deliveries are restricted to the Highgate Converter but there is uncertainty as to whether this is driven by reliability, economics, or both. A final decision/implementation will occur by October 2022. A diagram of the planned emergency configuration is below. Maximum load for the following substations that have a good possibility of being added to this block include:

- South Alburgh = 6.5 MW
- Sheldon = 2.6 MW
- Enosburg = 5.0 MW
- Berkshire = 3.6 MW
- Richford = 4.4 MW
- Westrock = 1.9 MW
- TOTAL = 24.2 MW

Newport Block

The Newport Block consists of four interconnection points directly with VEC. Currently this block ranges from 0 MW (e.g., being fed from VELCO) and 20 MW (e.g., fed from HW) on average with a maximum of 30 MW in one hour. 2021 load on these four interconnection points includes:

- Norton = 200-300 kW
- Canaan = 3-3.5 MW
- Derby Line = 1 MW
- Newport = 15 MW
- TOTAL = 19.8 MW

Without any investment, VEC could add the Irasburg 1A circuit (1.5 MW) through its distribution system to this block. This implementation is planned for the end of Summer 2022. VEC is also in the process of analyzing adding all circuits from the Irasburg substation (3.5 MW) but there are capacity concerns that need to be addressed. One option is to feed the entire Irasburg substation of the 46-kV system. However, there are issues with KCW's electrical flow and capacity issues on the 34.5 kV line owned by GMP. While GMP may have plans to upgrade this line, these would have to be addressed before we could proceed with this option. Another option is for VEC to invest approximately $100,000 into its distribution system

Utilizing and expanding the Highgate and Newport Blocks have the potential for significant positive impacts to VEC and the entire state of Vermont during a capacity deficiency. A summary of the impact includes:

- Highgate Block = 24 MW currently with another 25 MW possible
- Newport Block = 25 MW currently with another 1.5 MW possible
- Total = 75.5 MW

VELCO's peak load in 2021 was approximately 950 MW which means VEC could reduce that load by eight percent. VEC's peak load in 2021 was 84 MW which means 90 percent of its load could be shifted to HQ. These two large load reductions may mean VELCO and Distribution Utilities in Vermont would not need to shed load through "rolling blackouts" if ISONE England's call for load reduction (to VELCO passed down to the Distribution Utilities) was eight percent or lower. If ISONE England called for a greater load reduction, VEC may not have to participate in any "rolling blackouts" as it can move 90 percent of its system to be fed from HQ. This all hinges on if the ISONE England call for load reduction came when VEC was being fed from the United States.

Vermont Utilities Winter Preparedness Task Force

In the winter months there is an increased concern of an Energy Emergency directly resulting from a multi-day extreme cold weather event in New England. During such an event, availability of natural gas is limited to a point at which power generation cannot be sustained from pipeline energy. If equipped, resources switch to on-site fuel storage such as liquefied natural gas, liquid petroleum, and coal. These onsite fuel sources are finite and must be replenished to maintain the availability of those resources. Replenishment is anticipated to be difficult and not likely to be sustainable. An Energy Emergency will last until energy supplies can be restored to normal, likely because of warming temperatures.

VEC participates in Vermont's Winter Readiness Task Force to prepare in the event ISONE activates their Operation Procedure 4 for voltage reduction. VEC is actively working to develop protocols to meet voltage reduction requirements (e.g., "rolling blackouts") for the 2022-2023 season and will have them complete by the end of summer 2022. We are also actively working with municipal electric utilities that VEC serves to develop mutual understandings on how such voltage reductions will work (e.g., either treat municipalities like a VEC circuit or have each municipality conduct their own voltage reductions (e.g., "rolling blackout"). The general philosophy is to move as much load to Hydro-Quebec which is considered outside of ISONE and counts toward that voltage reduction requirement and to de-energize circuits for four hours before turning them back on. In addition to meeting the voltage reduction requirements of ISONE, we consider cold-load pickup (e.g., load in-rush) and other system impacts. However, VEC is one of four utilities in the state with the ability to conduct this type of voltage reduction (e.g., rolling blackouts) from its control center without the need to rely on manual switching in substations. Other utilities with similar capabilities include VELCO, GMP, and BED. The goal of the task force is as follows

- Maintain awareness of the ISONE 21-day Energy Assessment Forecast and Report and disseminate any forecasted energy concerns

- Coordinate plans to accomplish a multi-day load shed event to include load served by utilities without a staffed control center
- Coordinate load shed plans with identified critical loads

In the event of an Energy Emergency

- Low probability high consequence scenario is a five-day continuous cold spell which could lead to an Energy Emergency due to lack of adequate natural gas.
- This could lead to the use of all Emergency Procedures within New England including OP7 (Load shedding).
- All New England Control Centers are working with ISONE to update load shedding procedures including rolling outages.
- Vermont Utility Winter Readiness Task Force is working to coordinate all the state utilities' plans.
- This is a regional issue that will continue beyond 2022.