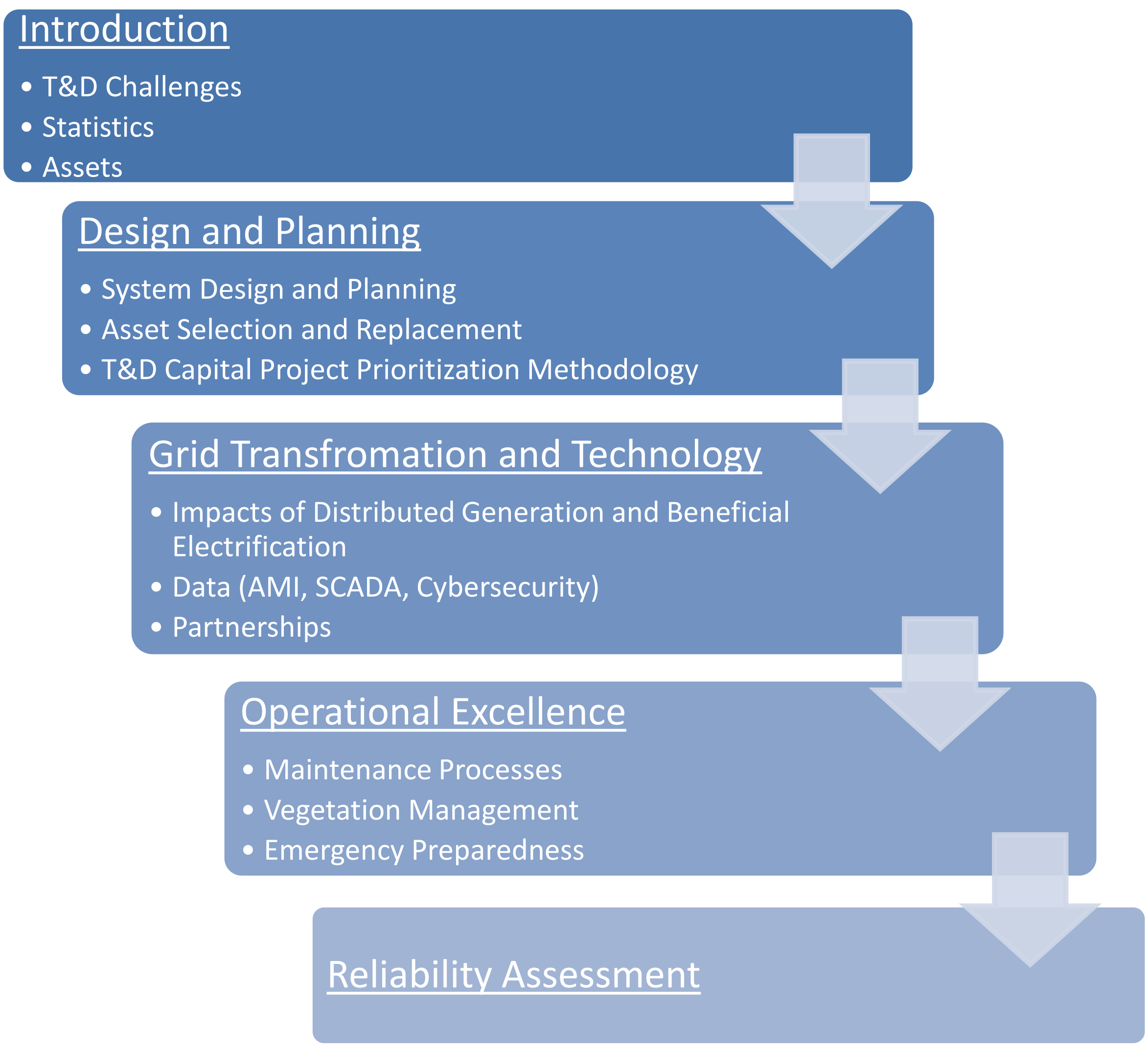
# 4 Assessment of Transmission and Distribution System

## 4.1 Introduction

This section of the IRP contains an overview of VEC's Transmission and Distribution (T&D) strategies and internal programs. VEC's 2018 member survey confirmed that cost, quality of member service, and reliability continue to be the most important drivers for member satisfaction for both commercial and residential members. With growing consumer expectations, renewable proliferation and regulatory policy and incentives driving significant changes to the electrical grid, it is becoming increasingly challenging to ensure that VEC is providing the least cost of service while maintaining a high level of reliability and member service. This plan addresses the challenges opportunities resulting from these changes.

Section 5 – Action plan lists VEC's T&D Capital Plan, strategies for reliability improvement, and operating and maintenance plans.

### 4.1.1 General Overview



## 4.2 Transmission and Distribution Challenges

VEC's philosophies, programs, and corresponding T&D capital plan are shaped by four challenges, each of which has a distinctive set of solutions. The challenges are (1) prioritizing investment to improve the condition of VEC infrastructure, (2) increase in outage quantity and duration resulting in lower reliability, (3) beneficial electrification, and (4) distributed generation.

### 4.2.1 Prioritization of Investment to Improve Condition of Infrastructure

VEC's largest challenge is prioritizing investment to maintain and improve an extensive and aging infrastructure while balancing cost to the membership. This infrastructure is approaching its end of usual life in many sections of VEC's territory, and in some cases has passed its expected life. The biggest area of concern is VEC's distribution system, which encompasses 71 percent of VEC's total assets, as discussed below:

- **Aging and high loss conductor –** 6A Copperweld, #6 Steel, and 8D Amerductor represent around 10 percent (568 conductor miles) of VEC's distribution plant. These wire types and sizes were common, cost effective conductor choices when rural electrification occurred in the 1930s, but they are now nearing end of life and are not compatible with current materials and construction practices. In addition, since resistance increases greatly for small wire, line losses increase which leads to higher operating costs.
- **Direct buried and unjacketed underground –** VEC has recently seen an increase in the quantity of direct buried and unjacketed cable underground failures. Direct buried cable is not in conduit, and unjacketed underground can lead to a missing or detached concentric neutral. These types of installations, which were commonly used in the 1970s, are both more susceptible to failure and harder to locate when a fault occurs, which can cause longer outage durations.
- **Line locations and access –** Almost 60 percent of VEC's distribution lines are not located roadside. Much of VEC's system was constructed in the early to mid-1900s, when much of Vermont was pastured or open land, and placement of utility lines was determined by identifying the shortest distance between two points to save on costs as well as line design time. Many of these cross-country lines cannot be easily accessed by bucket trucks and as a result, restoring outages is costly and time-consuming.

Figure 4.2.1.A   A pole in wetland in French Hill, Johnson

- **Code violations –** VEC has found some equipment or installations that do not meet National Electrical Safety Code (NESC) or National Electric Code (NEC). As part of VEC's 5-year maintenance plan, these installations are proactively identified and violations will be mitigated to ensure employee and public safety. Many of these were built many years ago, and in some cases were caused by members building homes/structures underneath existing electric lines. In many cases, these issues are resolved with a taller pole but sometimes they require line relocations, reconductoring, or equipment replacement.

Figure 4.2.1.B     NESC violation above addition in Grand Isle, Vermont

Capital investment from 2008-2018 focused largely on substation automation and rebuild projects with limited discretionary distribution investment. The two charts below show VEC's assets in millions and capital investment from 2008-2018

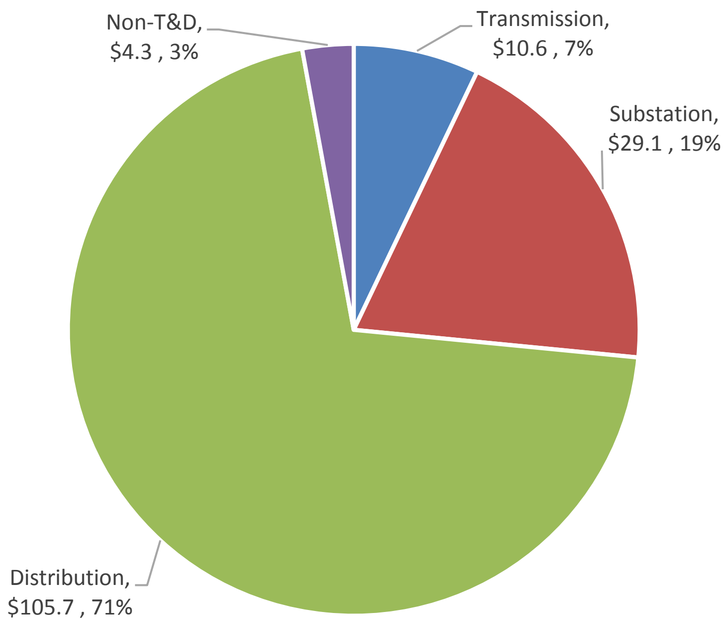



*Figure 4.2.1.D VEC assets (in millions)*

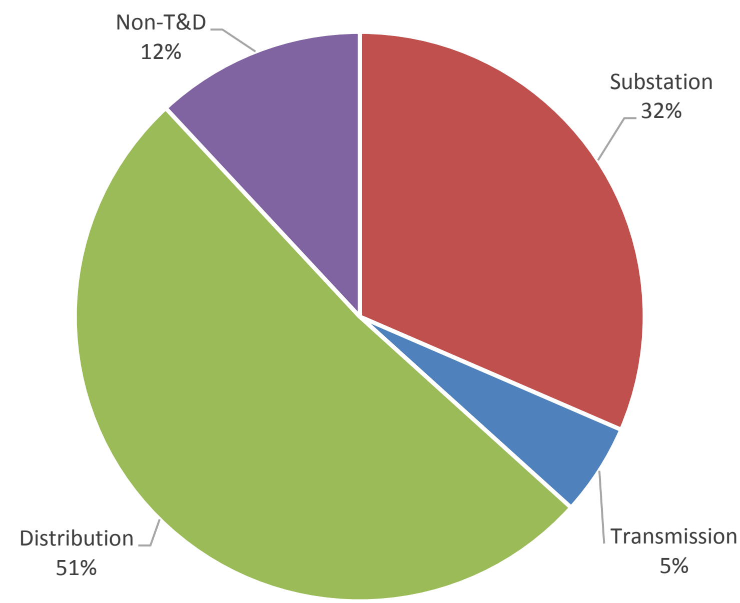



*Figure 4.2.1.C VEC capital investment (2008-2018)*

As a result, VEC's distribution assets are in need of additional investment and thus VEC will shift investment from substation spending to meet this need.

## 4.2.2 Reliability

VEC has met its SQRP reliability targets for the past 9 years. However, VEC has seen a recent trend resulting in an increase in both outage frequency and duration. In fact, in January of 2019, VEC did not meet its 12-month average Customer Average Interruption Duration Index (CAIDI) goal of 2.6 for the first time since June 2013. The chart below shows VEC's historical outage and duration totals from 2014-2018.

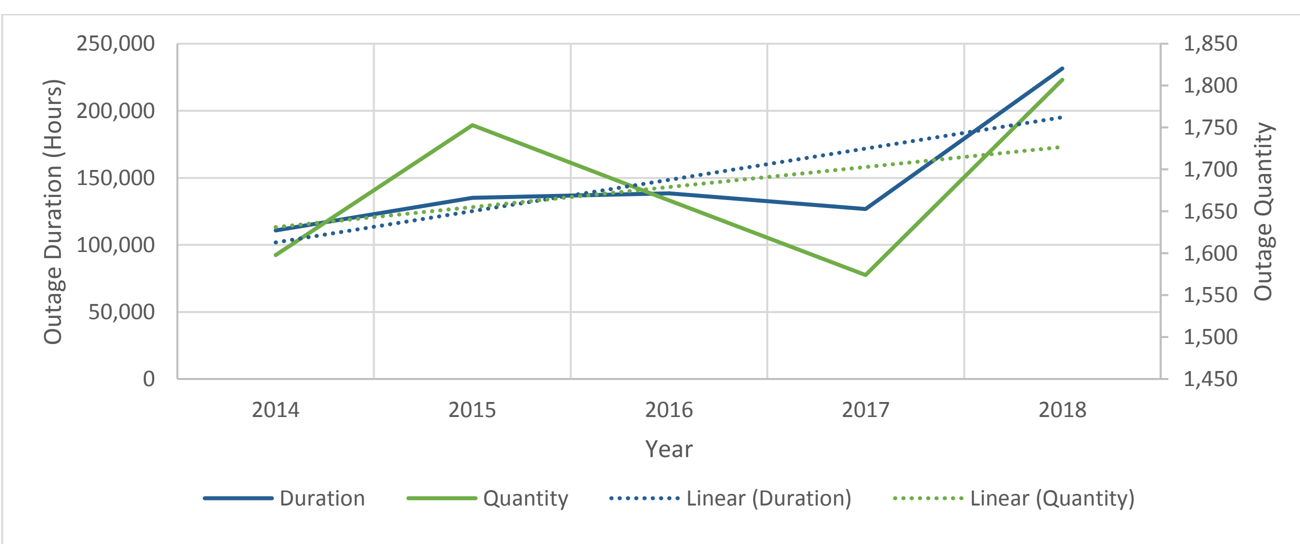



*Figure 4.2.2.A VEC historical outage duration and quantity totals*

Tree outages represent the largest portion of both duration and quantity of outages, and VEC is in the process of revising its vegetation management plan to address these concerns. Furthermore, VEC hopes that continued sectionalizing and investment into its worst performing circuits and line sections will make improvements to its members' reliability.

### 4.2.3 Beneficial Electrification

Beneficial electrification includes technologies such as electric vehicles, heat pumps, or energy storage. VEC's 2018 total of new electrification is around 1.4 MW (35% CCHP or HPWH, 29% EV's or PHEV's, 40% CAP). The chart below shows VEC's total forecasted beneficial electrification load increase is around 11MW by 2023, which is about 13% of VEC's system peak (approximately 85MW).

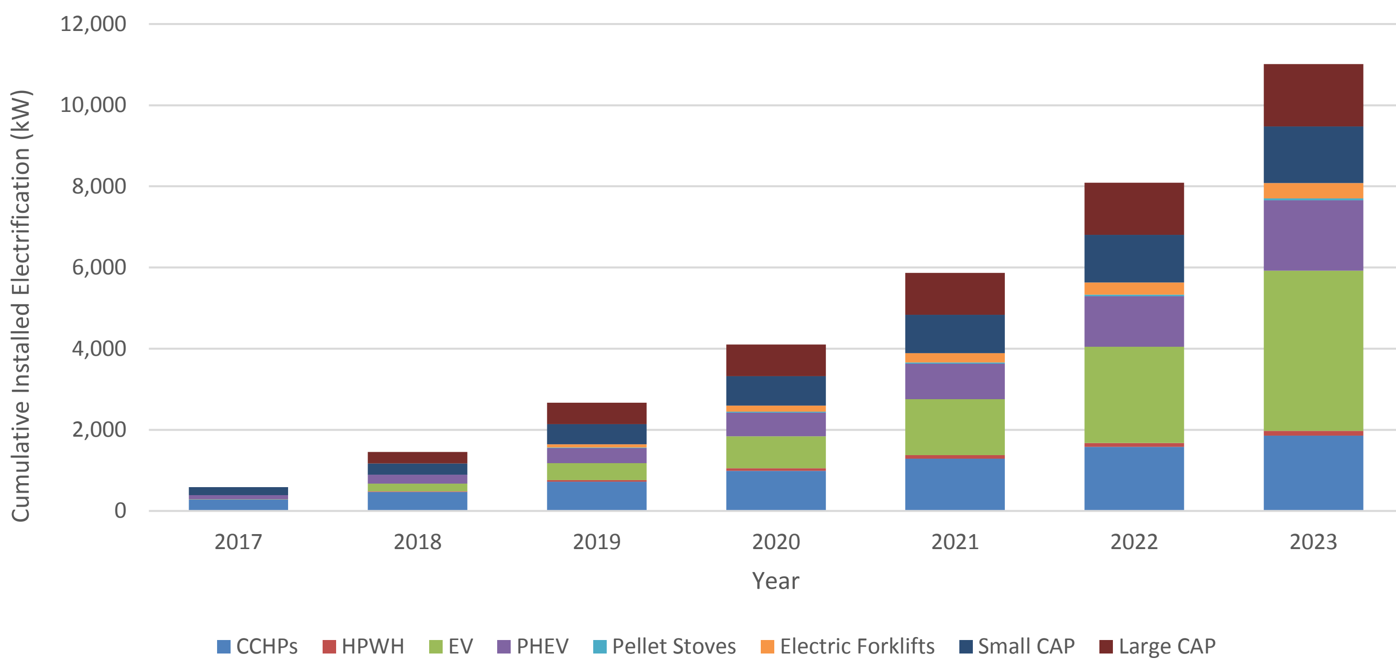



*Figure 4.2.3.A Cumulative installed electrification after diversification (kW) by year and category*

As with any type of load growth, the quantity and location of these technologies can have significant impacts on the electrical grid. Given the limited penetration of these technologies on VEC's distribution system today, these impacts are relatively minimal; however as incentives and growth continue, the likelihood of VEC infrastructure upgrades and member owned upgrades related to these technologies increases. The implementation of load control and rate structures to manage demand during peak times will greatly determine the impact of this load growth.

In addition, VEC receives limited notification for these types of loads making it critical to perform annual system planning and identify alternatives for lack of notification.

### 4.2.4 Distributed Generation

VEC continues to see a rapid rise in distributed generation on its system. VEC currently has 33.5 MW of distributed generation, 13.7 MW of which is net-metering solar. In addition, around 8.2 MW of pending projects -- primarily group net-metering projects -- also sit in VEC's interconnection queue. Furthermore, using the baseline power supply forecast, another 20 MW of distributed generation (17 MW of which will come from net-metering solar) is expected to come online by 2023.

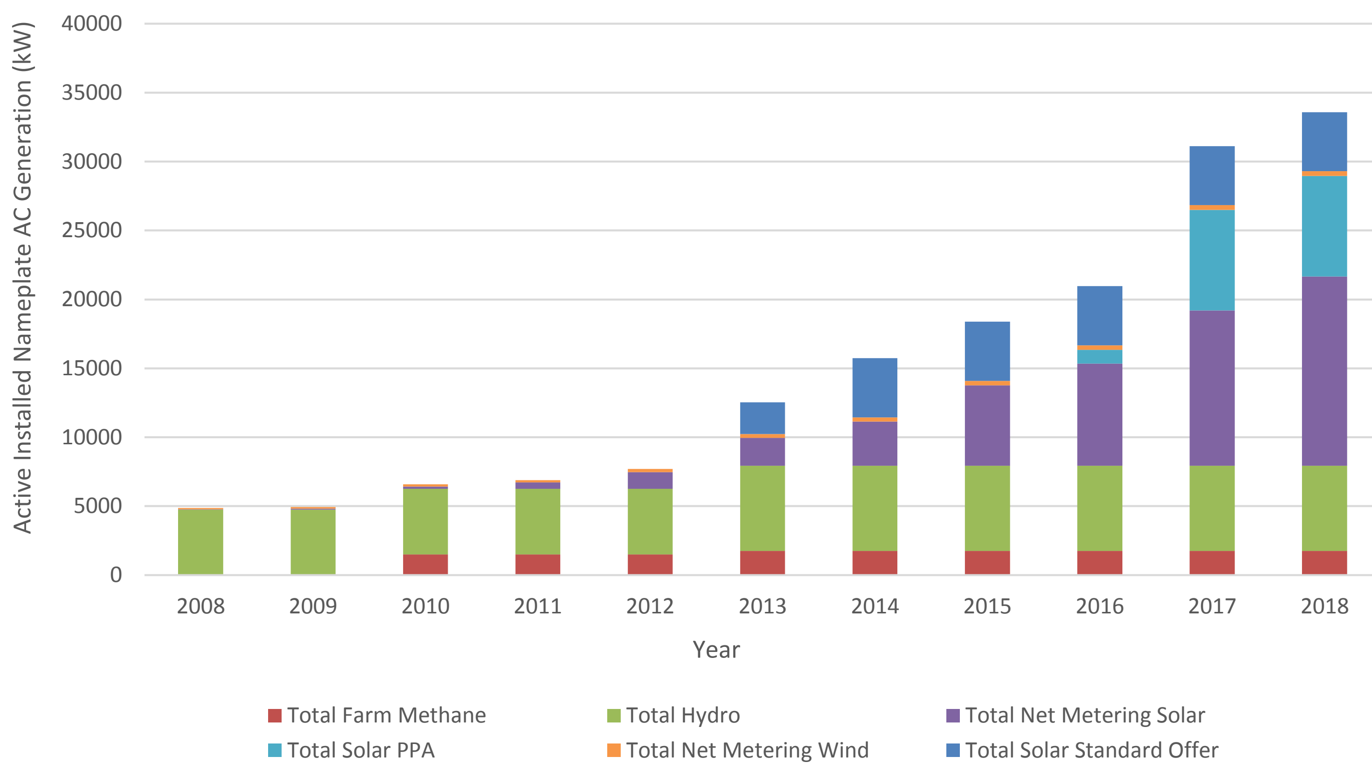



*Figure 4.2.4.A Distributed generation increase since 2008.*

This growth requires VEC to re-prioritize limited resources to reviewing interconnection applications (around 380 annually) to ensure grid stability. While some of these applications are completed quickly, many can take years to proceed through a study and CPG process.

## 4.3 Statistics

| | |
|---|---|
| Services per Mile | ***~14 per Mile*** |
| Peak Load | ***87.55 MW (01/02/2014)*** |
| Distribution Poles | ***55,263*** |
| Primary Distribution Overhead Line Miles | ***~2,438 miles*** |
| • Single Phase | ***~1,996 miles (82%)*** |
| • Two Phase | ***~39 miles*** |
| • Three Phase | ***~403 miles*** |
| Primary Distribution Underground Conductor | ***~303 miles*** |
| Equipment (Reclosers, Sectionalizers) | ***~450*** |
| Line Regulators and Capacitors | ***108, 113*** |
| Transformers | ***~23,000 (Pole), ~2,000 (Ground)*** |
| Transmission Poles | ***2,575*** |
| Transmission Line Miles | ***136 Miles*** |
| Substations | ***35 (Distribution), 2 (Transmission)*** |
| Metering Points | ***3 (All with GMP)*** |
| Fiber Optic Cable | ***183 Miles*** |

*Table 4.2.43.4.2.4.A VEC T&D statistics*

## 4.4 Assets

VEC is a rural electric power utility made up of legacy Citizens Utilities and VEC assets. VEC's T&D strategy is to provide safe, affordable, and reliable power to all of its members. However, its unique network of poles, wires, and assets poses unique challenges. Unlike many rural electric cooperatives in the country, VEC is not currently an RUS borrower, but because it had been an RUS borrower prior to bankruptcy in 1995, parts of its distribution system were built to RUS standards. However, the legacy Citizens assets did not follow RUS standards and as a result, it has been a continual challenge, since the acquisition in 2004, to merge the two electrical systems.

VEC's assets are made up of the following categories:

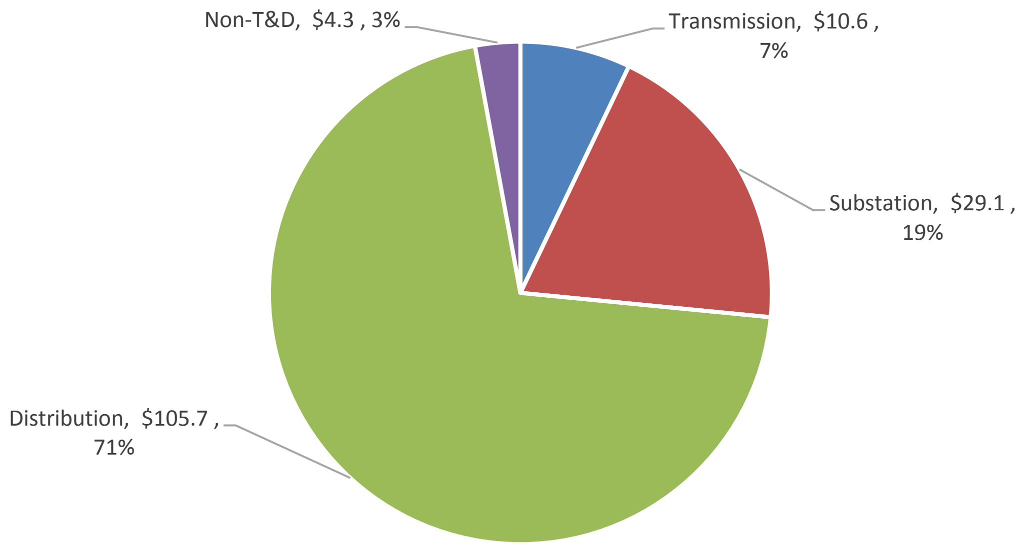



*Figure 4.2.4.A VEC assets (in millions)*

The largest category is VEC's distribution system assets:

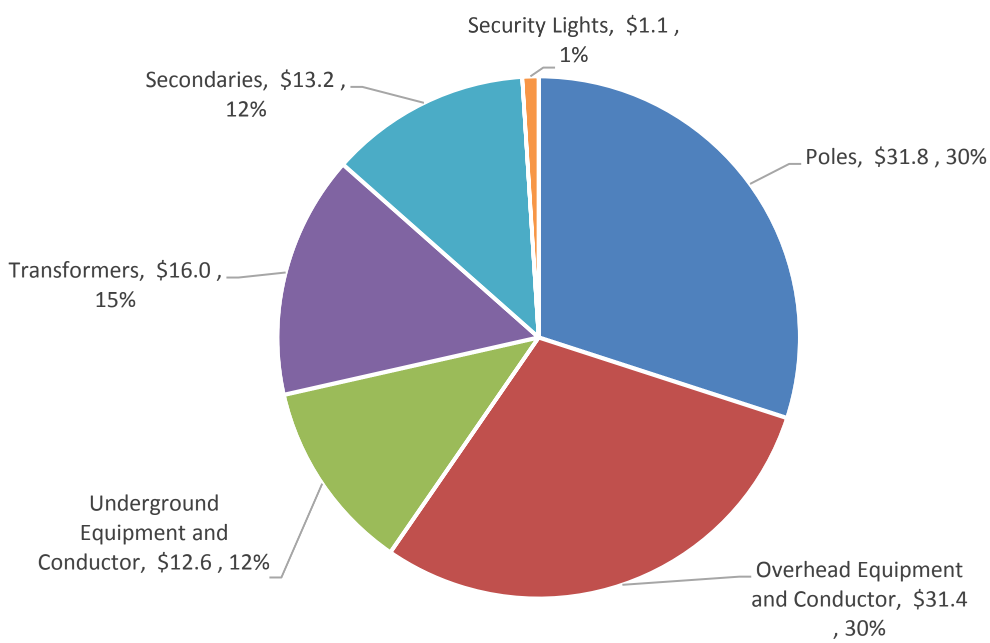



*Figure 4.2.4.B Distribution assets by sub-category in millions)*

To feed this distribution system (71% of assets) VEC owns and maintains a sub-transmission network that stretches from Canaan to the Islands of Alburgh and South Hero. Our transmission network is long, predominantly rural, and represents roughly 7% of total assets. The remaining 19% of assets are made up within VEC's 40 distribution substations, transmission substations, and primary metering points.

## 4.5 Design and Planning Philosophies

### 4.5.1 Design Criteria

VEC conducts distribution planning to ensure it can deliver power safely and reliably with a focus on voltage performance that meets ANSI Standard C84.1. VEC has developed criteria that detail these planning requirements. These criteria ensure both the adequate performance of the power system and the safety of those working on the system. More detailed information regarding VEC's distribution criteria is available in Appendix - F.

#### Distribution

VEC's standard distribution system voltage is 12.47 kV/7.2 kV grounded wye. In some areas, VEC also utilizes 34.5 kV/19.9 kV distribution voltage. VEC still operates around 90 miles of 4.16 kV/2.4 kV grounded wye lines; however, we are steadily converting these voltages to the standard 12.47 kV/7.2 kV grounded wye.

#### Transmission

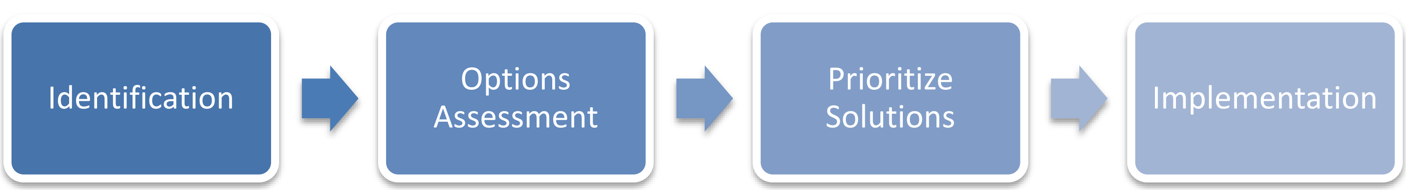
VEC's standard subtransmission voltages are 34.5 kV and 46 kV. VEC transmits power from VELCO, GMP, Eversource and Hydro Quebec on its subtransmission system to its distribution substations and large industrial members. VEC strives for "N-1" planning criteria for all looped transmission lines and radial transmission lines. The term N-1 refers to the failure of important equipment. "N" is the total number of components that the system relies on to operate properly. The number subtracted from N is the number of components that fail in a given scenario. Therefore, N-1 means that only one component has failed. N-1-1 means that two components have failed, which is generally worse than having only one fail. To achieve N-1 on radial transmission lines, VEC looks for feeder backup opportunities.

More detailed information regarding VEC's transmission criteria is available in Appendix - F.

### 4.5.2 System Planning

In order to provide the least cost solution while monitoring efficiency, enhancing reliability, and allowing for growth, VEC approaches system planning as a balance between day-to-day analyses and longer range holistic reviews of the system.

While the timing for day-to-day analysis and overall system reviews are different, VEC uses a similar process for both categories:



- **Identification** – Examination and definition of project/area versus design criteria, which will provide triggers for further review.
- **Options Assessment** – Detailed analysis via software tools and data to solve problems identified. Proposed solutions are developed using engineering calculations, cost/benefit analysis or power load flow simulations as required.
- **Prioritize Solutions** – Least cost, most feasible and most reliable solutions are recommended. Projects are prioritized, timelines are established, and detailed cost estimates are developed and proposed for capital budget inclusion.
- **Implementation** -- Once approvals are secured, projects are scheduled, constructed, and closed out.

## Distribution System Planning

VEC has 38 distribution substations and primary metering points that supply 74 distribution circuits. Distribution system planning is broken up into four general categories:

- Forecasting (load and generation)
- Power Flow Analysis (peak capacity, contingency, ampacity)
- Power Quality Analysis (voltage analysis)
- Fault Analysis (protection and coordination)

VEC performs various studies to address these four categories that are described in further detail below:

### System Load and Voltage Study

The system load and voltage study reviews all of VEC's 74 distribution circuits via equipment loading, voltage performance, and phase load balancing design criteria. VEC utilizes Supervisory Control and Data Acquisition (SCADA) and Automated Metering Infrastructure (AMI) data as well as its Milsoft WindMil model to identify system constraints and appropriate solutions. VEC completes this system-wide study annually to identify constraints up to five years from the study completion. Given the substantial increase in distributed generation as well as technological developments such as electric vehicles and heat pumps, planning outside the five-year horizon is more uncertain than it ever has been. The report includes the following tasks:

- Identification of peak loads for each substation.
- Calculations of percent unbalance of the phase amps at the substation low side bus.
- Identification of any substation or distribution equipment that is overloaded.
- Identification any single phase circuits that are loaded greater than 288 kVA (40 amps at 7.2 kV)
- Identification of any circuit elements experiencing voltage outside of 0.95-1.05 per unit.
- Identification of any distribution circuits with greater than two percent voltage unbalance.
- Identification of expected five year load growth
- Allocation of five-year load growth across the system to identify any overloads or violations of loading and voltage criteria. Two allocations are completed:
    - Even distribution – equal application of percentage load growth across the system
    - Selected distribution – application of percentage load growth based on net metering quantities (electric vehicles and heat pumps) and commercial/sugaring locations (Tier 3 Clean Air Program)
- Identification of solutions to any criteria violations.

VEC's 2018 study assumed five percent load growth, as Tier 3 forecasts had not yet been completed. Further discussions on the 2019 study and constrained areas are identified in the Beneficial Electrification section below.

**4.900 Reliability Report**

Public Utility Commission (PUC) Rule 4.900 requires that VEC file a 4.900 Reliability Report annually. This report contains a detailed assessment of VEC's outage performance, as well as a plan for how to improve reliability to its members. Target reliability metrics used in the report are defined via VEC's Service Quality and Reliability Plan (SQRP) approved by the PUC. Through this analysis, VEC identifies its top 10 worst performing circuits. VEC rates its top ten worst performers by prioritizing the number of outage events first and then customer hours out. VEC reviews these worst performers based on type and location of the outages in order to develop projects to mitigate these outages in the future.

In addition to the worst performing circuit analysis, VEC develops a quarterly "three or more" report. This report identifies all line sections that have seen three or more outages within the last 365-day period. These line sections are prioritized by the number of outage events first, and then by the customer hours out. VEC's Engineering Department shares this information with our four districts and works to develop capital or maintenance projects to attempt to mitigate these outages moving forward.

**System Contingency Analysis**

This analysis reviews substation and feeder contingencies by identifying voltage or loading constraints that may occur during an N-1 or scheduled maintenance event. Along with identifying the constraints, the study identifies feeder backup opportunities or other capital upgrades. These projects enhance reliability and reduce cost by adding greater operational flexibility to the system.

## Transmission and Sub-Transmission System Planning

VEC coordinates with other Vermont utilities to ensure reliable electric service to VEC's members and the customers of other utilities that are fed from VEC's sub transmission facilities such as Barton and Orleans. These Vermont utilities include Green Mountain Power as well as the villages of Barton, Orleans, Swanton and Enosburg.

In addition, VEC works very closely with VELCO, Vermont's transmission operator, to provide information and collaborate on system improvements. VELCO in turn works with New England's regional electric grid operator, ISO-New England (ISO-NE).

An example of this collaboration is the 2018 joint VEC/GMP Cambridge substation rebuild which substantially improved the reliability of five distribution substations serving approximately 3,700 GMP and VEC customers.

In addition, VEC is a member of the Vermont System Planning Committee (VSPC) and brings forward all reliability issues at the substation and transmission level to determine whether a potential exists to resolve the issue with some configuration of energy efficiency, demand response and distributed generation, or a hybrid of transmission and non-transmission solutions.

If the project is eligible via either the Docket 7081 VSPC Non-Transmission Alternatives Screening or the Docket 6290 Screening tool, the VSPC and VEC will work together to identify solutions. All the electric utilities in Vermont complete this screening on an annual basis.

VEC anticipates that Tier III efforts will result in load growth; however, VEC expects this growth to occur outside of VEC's 10-year system planning horizon. As a result, the majority of the projects that are reviewed via Dockets 7081 and 6290 are categorized as either asset management or reliability improvement projects.

### 4.5.3 Power Factor

Power factor is the ratio between the real power and apparent power. A common analogy that is used is a mug of beer. The beer has some liquid (real power or watts) and foam (reactive power or VARs). The whole mug is the apparent power (kVA).


*Table 4.5.3.A Beer mug power factor analogy*

VEC bills only for the liquid, which turns the meter. The foam is necessary to maintain voltage and that reactive power needs to come from somewhere, ideally as close as possible to where the real power is being used.

With regard to the VEC system as a whole, VEC is striving to maintain a power factor at or above 0.95 lagging and equal to or less than unity. In order to meet this goal, VEC measures the power factor at each of its substations. Using this information, VEC ensures that the system is operating as efficiently as reasonably possible. When appropriate, VEC may require that power factor correction equipment be paid for and installed by the member. The revenue meter for commercial accounts measures the power factor.

In addition, ISO-NE and VELCO require VEC to maintain a power factor of between 0.95 lagging and unity for all of its primary metering points with other utilities. Commercial accounts are also required to meet a power factor value between 0.95 lagging and unity.

Typically, VEC achieves power factor correction using fixed capacitors on the distribution circuits. By placing the capacitors on the distribution circuits where the VArs (Volt Amperes Reactive, i.e., reactive power) are needed, we avoid excess current across the distribution lines, thus reducing losses. Placing capacitors on the distribution system also affects system voltage, and we take these affects into account. Fixed capacitors are a relatively inexpensive solution for voltage support and often times also provide the necessary VAr support that the load requires.

In some cases, voltage support is required but the VArs are not, which can cause leading power factors and line losses. In these instances, a voltage regulator may be the appropriate solution. Voltage regulators are more expensive and require periodic maintenance to function properly. Increased conductor sizes, voltage conversions to higher voltages and the addition of multiple phases to help balance loads and reduce phase line currents may also be required.

VEC continues to review alternative methods of improving system voltage such as adding voltage regulators and installing larger wire to reduce voltage drop on its long radial lines. VEC completes this analysis on an annual basis as part of the System Load and Voltage Study. The goal is to find a balance between low losses, affordability, and system operability.

### 4.5.4 Phase Balancing

In order to achieve an efficient distribution system network, VEC has developed design criteria for distribution line loading and voltage:

- Three-phase distribution line voltage shall be less than two percent unbalanced.
- The substation low side bus phase currents shall be not more than 20 percent unbalanced.
- Winter or summer model predicting loading greater than 40 A on single phase taps shall be addressed either with multi-phasing, tie lines open position changes to reduce load, or voltage conversions.

More detailed information regarding VEC's distribution criteria is available in Appendix-F.

Balancing load between phases improves the efficiency and operability of the distribution circuits. Balancing phase loading helps to keep voltage balanced and creates a better foundation for voltage regulation on long single-phase taps and to three-phase customers. A balanced system also reduces neutral current on three-phase lines, leading to a reduction in losses.

VEC aims to reduce the number of large radial single-phase lines to manage more easily the system from a load balancing perspective. Having multiple phases also improves VEC's ability to serve new load by freeing up capacity and improving system voltage through reducing high single-phase line loading.

### 4.5.5 Voltage Upgrades

Per VEC's Design Criteria, voltage performance must meet ANSI standard C84.1. Basic Criteria include:

- System voltage equal or above 114 V (0.95 per unit) and equal or below 126 volts (1.05 p.u.),
- Target consumer voltage at the meter is 120V +/- 5% (114V – 126V), and
- Conductors below normal ampacity rating (< 1 p.u.), and
- Equipment below normal ampacity rating (< 1 p.u.).

While VEC attempts to analyze the system each time a new project is added and every three years as a whole, these proactive efforts do not guarantee acceptable power quality for all VEC's members. VEC prioritizes power quality complaints and investigates them immediately. VEC gives high priority to power quality incidents that require capital improvements.

VEC continues to operate about 90 miles of 2.4kV lines, all of which are located in the legacy Citizens Utilities system. VEC does not have an explicit timetable for converting its lower voltage circuits to standard 7.2 kV. Voltage conversions are driven by a number of considerations including but not limited to low voltage complaints, opportunities arising from the need to replace deteriorating assets, and capacity constraints. VEC has eliminated all existing 2.4kV lines where loss savings have justified a capital upgrade. As with all capital upgrades, VEC prioritizes those projects that provide the greatest value to its membership.

### 4.5.6 Voltage Regulation

All of VEC's electric substations employ bus voltage regulation as opposed to feeder voltage regulation. This reduces capital costs and maintenance costs by minimizing the number of voltage regulators on the system. Generally, we set a base voltage set point, bandwidth, and time delay. These settings are to keep the load within acceptable range and to minimize regulator switching and mechanical degradation.

The VEC system has many relatively long single-phase distribution feeders with sparse loading per mile and small conductors. During peak times, we need to boost bus voltage to stay within acceptable range further out on the feeders. An example voltage profile of one of these feeders (33-mile circuit from Island Pond 46 Substation to Guildhall) is provided below:

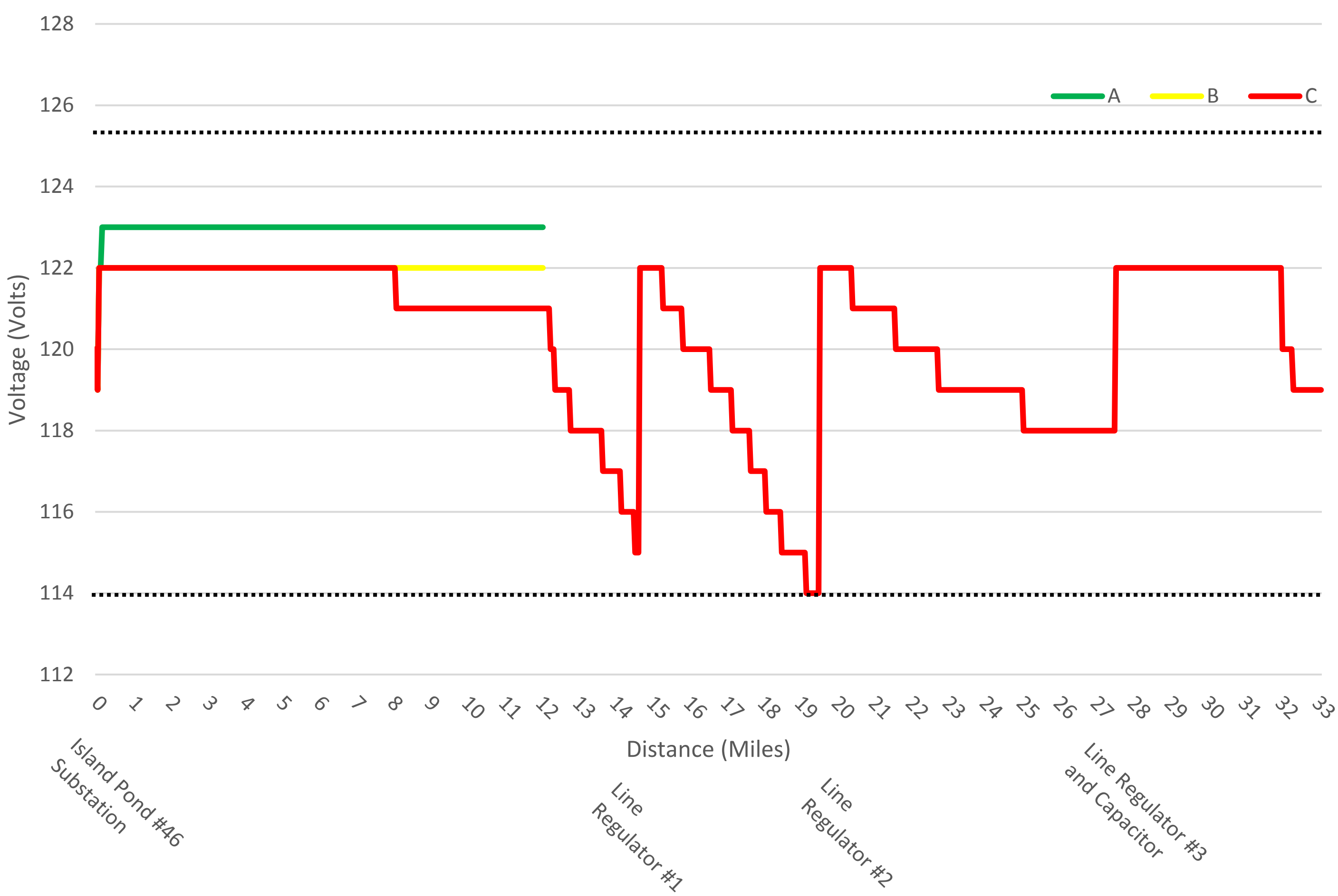



*Figure 4.5.6.A Island Pond #46 substation to Guildhall voltage profile*

VEC has reviewed the potential costs and benefits of implementing a Conservation Voltage Reduction (CVR) program but has no immediate plans to install this on its system. CVR lowers the voltage during high resistive load times to conserve energy. By lowering the voltage to a resistive load such as an incandescent light bulb, the current would also be reduced proportionately, hence decreasing losses and costs.

Motors and pumps require constant power, so if the voltage is reduced, the motor draws more current in order to maintain the same amount of power output (Power = Voltage x Amperage). This can make regulating the line voltage more difficult: if we were to lower the bus voltage, the line current may actually increase leading to further voltage drops and causing the end of line voltages to be below an acceptable range.

In recent years, due to efficiency programs in Vermont, lower watt alternatives such as Compact Fluorescent Lamps (CFLs) and Light Emitting Diodes (LEDs) have displaced resistive lighting load. Both of these alternatives draw almost constant power across their allowable voltage range. This displacement has made CVR less effective at conserving energy than in the past when incandescent lighting accounted for nearly 80 percent of residential service loading.

VEC employs voltage regulator load compensation settings in some circumstances to mitigate the impact of larger solar generation projects located further from the substation that generate the most during times of low feeder loads. Load compensation settings set the bus voltage to a lower voltage during low load times and increase the bus voltage as the load increases. The low bus voltage during low loads and peak generation tends to keep the line voltages within tolerance for all the feeders out of the substation. These settings would be determined by the project's system impact study and due to the particular location on the feeder, the conductor size, generation capacity and associated voltage rise from the generator as the current travels to the load that appears further from the source than during peak feeder loading.

### 4.5.7 Collaboration with other Entities

VEC maintains several joint substations with Green Mountain Power (GMP) and VELCO.

- GMP – Richmond #8 Substation, Cambridge #3 Substation, Jay Tap #39, Taft's Corners #9 and Lowell #5 Substation
- VELCO - Jay Tap #39, Newport #44, South Hero #29, and Taft's Corners #9

By way of example, in 2016, VEC and VELCO completed a joint substation project at VEC's Newport #44 substation. This joint project saved on cost and increase reliability by adding a second transformer to the VEC distribution substation, which allows VEC to do maintenance without needing to take an outage to its Newport members.

Another example of collaboration is the 2018 joint VEC/GMP project to rebuild the Cambridge substation. VEC also recently worked with GMP to create a metering point on Snipe Ireland Road in Richmond, which retired over a mile of off-road equipment prone to outages.

#### LED Replacements Collaboration with VEIC

In October 2011, VEC began working with Efficiency Vermont (EVT) to determine our stranded costs for converting older streetlight technologies such as high-pressure sodium (HPS) to the more efficient LED technology. VEC determined that the average stranded cost was $175, and EVT offered a $100 per light rebate, leaving with the towns to pay VEC the $75 difference. We calculated how long it will take each town to recover the $75 in monthly savings from the more efficient LED lights. Some towns chose to eliminate unnecessary lighting, and others chose to convert to LEDs. To date VEC has replaced 1,171 of the older technology streetlights with 1141 LEDs in the following towns:

Albany, Alburgh, Bloomfield, Brighton, Canaan, Coventry, Derby, Derby Line, Derby Village, Eden, Franklin, Glover, Irasburg, Lowell, Morgan, Newport City, Norton, Sheldon, Westfield and Williston.

The kWh savings per year from these conversions is roughly 636,000. The project is ongoing, and VEC expects towns to complete conversions by 2021.

### 4.5.8 Line Relocation

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-1900s, 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 cannot easily access these cross-country lines and as a result, there is an increase in the cost and duration of line maintenance and outage restoration. Also, the poles on these cross-country lines are older and smaller class, increasing the likelihood that they cannot be climbed safely.

While it is unrealistic to move all of VEC's off-road lines to the road, there are many outage-prone, difficult to access, high maintenance cost (vegetation maintenance) locations where the cost and time to relocate the line are justified. VEC expects to see an increase in investment related to line relocations over the next five years.

This forecast is very dependent on the acquisition of easements and permits required to move lines to the road. In many cases, VEC has seen delays due to difficulty getting easements from members to cut trees necessary to relocate the line. In the event of easement difficulty, VEC may redesign the project or delay the project indefinitely.

When a VEC targets a project for relocation, VEC will coordinate with the following stakeholders:

- If Consolidated Communications is on the existing line or the line targeted for relocation, VEC will contact Consolidated Communications a minimum of one year in advance of project construction.
- VEC will contact landowners affected by the relocation during the easement procurement process.
- VEC will contact State, Towns, and Municipalities when a relocation occurs within town or state right-of-way in order to acquire permits.
- VEC will contact the Vermont Agency of Natural Resources for required permits such as Act 250 or wetland permits.

While moving lines to the roadside is preferred, there are other countervailing considerations, in addition to the cost, such as the aesthetic impacts and difficulties in obtaining needed easements or Act 250 permits. In general, it is not feasible for VEC to consider moving all of its lines from off-road rights of way to the road. VEC gives higher priority to lines that are currently inaccessible or present environmental challenges (wetlands or washout).

In the event that 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.

### 4.5.9 Duplicate Electric Facilities

In 2004, VEC acquired Citizens Utilities, identified significant overlap of the two systems, and has since made significant effort to consolidate the two systems, resulting in operations and maintenance (O&M) cost savings and in many cases improved reliability to VEC members. There are three remaining locations where there are opportunities for further consolidation, and VEC expects to complete this work by the end of 2020.

In cases where duplication exists with other utilities, VEC will work with the other utilities to eliminate this duplication.

### 4.5.10 Attaching Entities

VEC has several telecommunications entities that attach to its distribution system. These entities are broken down into three categories: Joint Use, Joint Ownership, and Attachee. Each entity utilizes the National Joint Utilities Notification System (NJUNS) web-based electronic work management tool to communicate and monitor work requests. The system provides extensive reporting, tracking, and searching capabilities that helps construction and monetary timelines, defines responsibilities, and monitor dual poles.

VEC recognizes that jointly occupied pole lines require larger poles of higher cost, but there are substantial cost savings when compared to the total investment dollars required of multiple companies if they constructed their own separate facilities. In addition, aesthetic and environmental impacts are lower with one line versus multiple.

#### Joint Use

Each entity owns their poles and can set or replace their own poles. The poles are jointly shared pursuant to rental agreements invoiced under 3.700 tariff rates. Both Waitsfield Telephone and FairPoint Classic are classified as Joint Use

#### Joint Ownership

VEC has three existing joint ownership agreements:

- Consolidated Communications (CCI) – Approximately 30,000 poles
- Franklin Telephone – Approximately 1,300 poles
- Washington Electric Cooperative (WEC) – Approximately 100 poles

VEC and the joint-ownership parties generally follow Inter-Company Operating Procedures (IOPs). Utility owners put these IOP's in place to ensure effective savings in capital investment for both companies.

**Consolidated**

CCI is VEC's largest joint owner with approximately 30,000 jointly-owned poles. Each company has a number of designated "maintenance areas" -- towns where it is responsible for pole sets - which are shown in the image below:

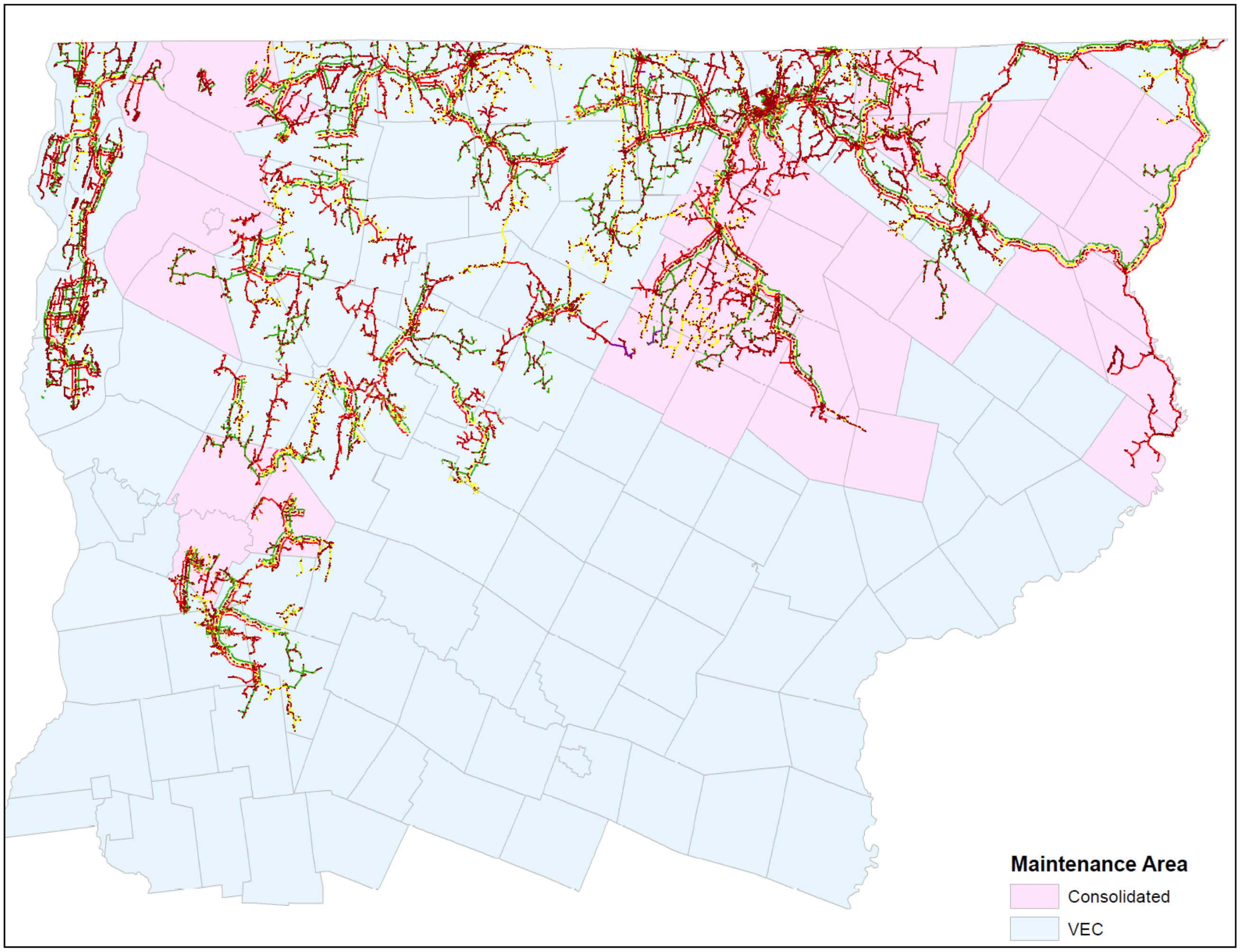



*Figure 4.5.10.A VEC and Consolidated Communications maintenance areas*

After nearly a year of negotiations, VEC reached an agreement with CCI effective 12/27/18 whereby VEC took over sole ownership of approximately 7,700 poles and updated certain IOPs. VEC continues to jointly own approximately 30,000 poles with CCI (~52 percent of poles).

## Attachee

Attachee entities are cable, antenna, communication providers, or municipalities that attach to poles owned by VEC under the terms of Vermont PUC Rule 3.7. Entities such as Comcast, Mansfield Fiber, Stowe Cable, and Verizon Wireless as are classified as an Attachees.

## Fiber and Broadband

In addition to the cable TV and phone attaching entities, described above, VEC continues to support the rollout of broadband, in particular to underserved communities in Vermont, in a way that is aligned with our mission to provide safe, reliable, least cost electricity to our members. VEC will support entities looking to expand broadband into underserved or uneconomic by leveraging our infrastructure, data, technical expertise, and processes. Specifically, VEC will provide:

1) Access to GIS information. After the entity signs a confidentiality agreement, we will provide free-of-cost electronic maps of VEC-managed poles in targeted areas for companies to plan possible projects.

2) Ability to brainstorm and co-create with our experienced infrastructure professionals by providing reasonable access to our engineers and operations experts. We will lend insight to determine optimal build routes including suggested ways, if needed, to close pole gaps. We will also share our future plans in those areas that may influence timing or provide shared opportunities.
3) Our commitment to following the established process and timelines for pole attachments and make-ready work. We have a proven record of meeting established and agreed upon timeframes and will work to meet or ideally beat those schedules.
4) Letters of support for grants or other funding opportunities if we can reasonably stand behind our experience with the organization.
5) Promotional assistance opportunities for VEC members to learn about new broadband service options in underserved markets. This can be through the VEC Members Discount Program or collaborative promotional campaigns.

### 4.5.11 Flood Plains

When it is considering locations to build or relocate a substation, VEC reviews all environmental impacts to ensure the least cost, most reliable solution. Among other considerations, VEC reviews current Flood Insurance Rate Maps (FIRMs) available through the Flood Map Service Center (MSC) for each substation location. The FIRM maps are the official public source for flood hazard information produced in support of the National Flood Insurance Program (NFIP). Unfortunately, VEC was unable to find FRIM maps for seven of our 38 substations.

For locations where a FEMA flood map was available, each location was mapped using a street addressing and or coordinate based search to find the most current (if available) flood map (FIRM panel or FIRMette) for the local area. VEC completed an evaluation of each location to determine if the site was located within the 100 or 500-year floodplain.

Where no FEMA flood map data was available, VEC performed an analysis using the local Vermont Department of Environmental Conservation (DEC) Flood Ready Atlas to confirm local flood data. **Based on available information VEC has determined that none of the 38 of its substations are in the 100 or 500 year flood plain.**

For more information on methodology and a table that provides further information for each substation, see Appendix-G.

### 4.5.12 Asset Selection and Replacement

The following section provides an overview of VEC's processes used to select all major equipment according to least-cost principles.

In general, on material purchases of $50,000 or greater, VEC's purchasing policy requires three competitive bids which are evaluated based on least overall cost, lead time, efficiency and quality of product. VEC may opt to purchase a unit that is higher in initial cost if that unit has a substantially shorter lead-time (where time is important) or if the unit to be purchases needs to be identical to the existing unit. VEC attempts to take all aspects of a product or service into consideration when deciding which to purchase.

#### Transformers

**Distribution Transformers**

For new distribution transformer purchases, VEC utilizes a spreadsheet developed from a tool provided by the Vermont Department of Public Service (DPS). The tool uses current and future energy and capacity market projections along with transformer nameplate data to calculate an estimate of lifecycle losses and resulting total ownership cost. VEC has provided the most recent version of VEC's transformer purchase spreadsheet in Appendix-M, which includes VEC's transformer acquisition multipliers. The spreadsheet utilizes the following measures:

- Avoided energy and transmission costs.
- VEC's Weighted Average Cost of Capital (WACC) and discount rate.
- Transformer loss factors that utilize average load and no-load losses over standard transformer sizes.
    - Load losses are also referred to as copper or winding losses and vary with the square of the current through the transformer winding.
    - No-load losses also referred to as iron or core losses and vary exponentially with the voltage applied.
- Avoided capacity costs which include fixed costs and capacity charges for power including on peak line losses.
- The cost of capacity responsibility reserve obligations.
- Expected load growth.
- Peak and average system losses.

The Department of Energy (DOE) CFR part 431 (Energy Conservation Program: Energy Conservation Standards for Distribution Transformers) outlines standards for distribution transformers. The DOE amended this document to increase the energy efficiency standards for distribution transformers beginning in January 1, 2016. While VEC takes into consideration the total cost of ownership identified in the tool described above, it has found through internal analysis that choosing the transformer with the lowest initial cost may provide the lowest total ownership cost option for the VEC membership. This is because the increased cost of losses for the lower initial cost unit never intersects with the higher initial cost, lower loss unit, over the 30-year financial life period of the transformers.

The following table shows the initial ownership cost, no load and full load losses, and total ownership cost of three 10 kVA transformers.

| Transformer | Sell Price | No Load Losses | Full Load Losses | 30 Year Losses | Total Ownership Cost |
|---|---|---|---|---|---|
| Howard 10 kVA | ***$590.86*** | $279.51 | $74.17 | $353.67 | ***$947.56*** |
| PPI 10kVA | ***$702.23*** | $255.55 | $75.23 | $330.77 | ***$1,036.61*** |
| Eaton 10 kVA | ***$907.42*** | $175.69 | $69.93 | $245.62 | ***$1,157.69*** |

*Table 4.5.12.A Total cost of ownership, no load, full load, and 30 year losses by transformer manufacturer*

The following graph presents the total ownership cost of a 10 kVA transformer by year and manufacturer:

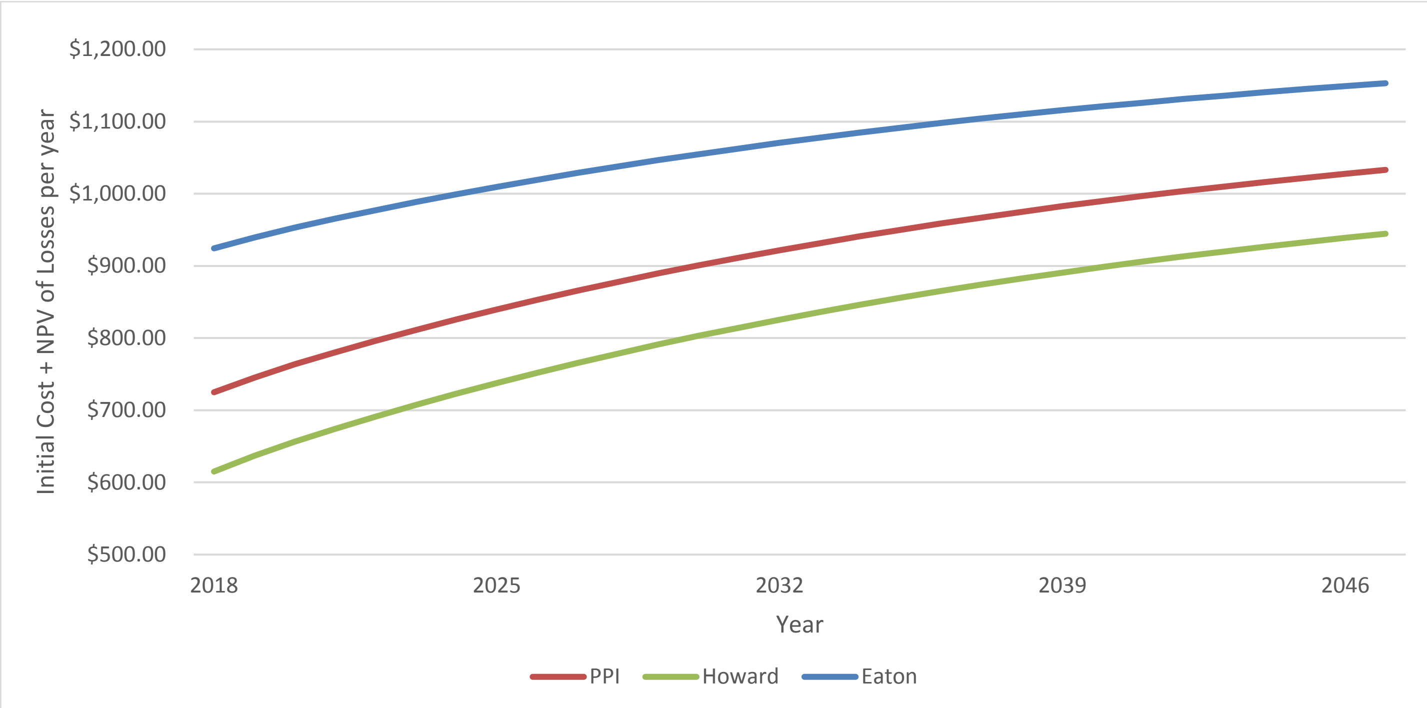



*Figure 4.5.12.B Total transformer ownership cost by year and manufacturer over 30 years*

As shown in the graph above, savings from fewer losses does not justify the increase in initial cost of a more efficient transformer.

There are two common types of overhead transformers, conventional and CSP (Completely Self-Protected). VEC has recently standardized on conventional transformers but still maintains some CSP inventory. VEC utilizes the following distribution transformer sizes:

- Pole Mounted – 1 kVA, 5 kVA, 10 kVA, 15kVA, 25 kVA, 37.5 kVA, 50 kVA, 100 kVA, 167 kVA
- Pad Mounted– 15 kVA, 25 kVA, 50 kVA, 100 kVA, 167 kVA, 250 kVA, 333 kVA

The smallest transformer size VEC utilizes on residential loads is a 10 kVA pole mounted transformer while 1 and 5 kVA transformers are used for station service and street lights.

VEC personnel identify the proper transformer size to ensure high-quality electric service and lowest life cycle cost for VEC membership. VEC has found that a typical residential member will draw around 3 kVA and in some cases up to 8 kVA. A 10 kVA transformer is utilized for residential loads which would allow for an additional member to be added without changing the transformer.

For commercial loads, VEC utilizes a required member load sheet and comparable sized loads to determine the transformer size needed. VEC also regularly monitors loading on larger transformers typically associated with commercial or small industrial members to ensure efficient transformer sizing.

Utilizing the calculated losses of the transformer purchase tool VEC was able to model the approximate lifecycle losses based on transformer size.

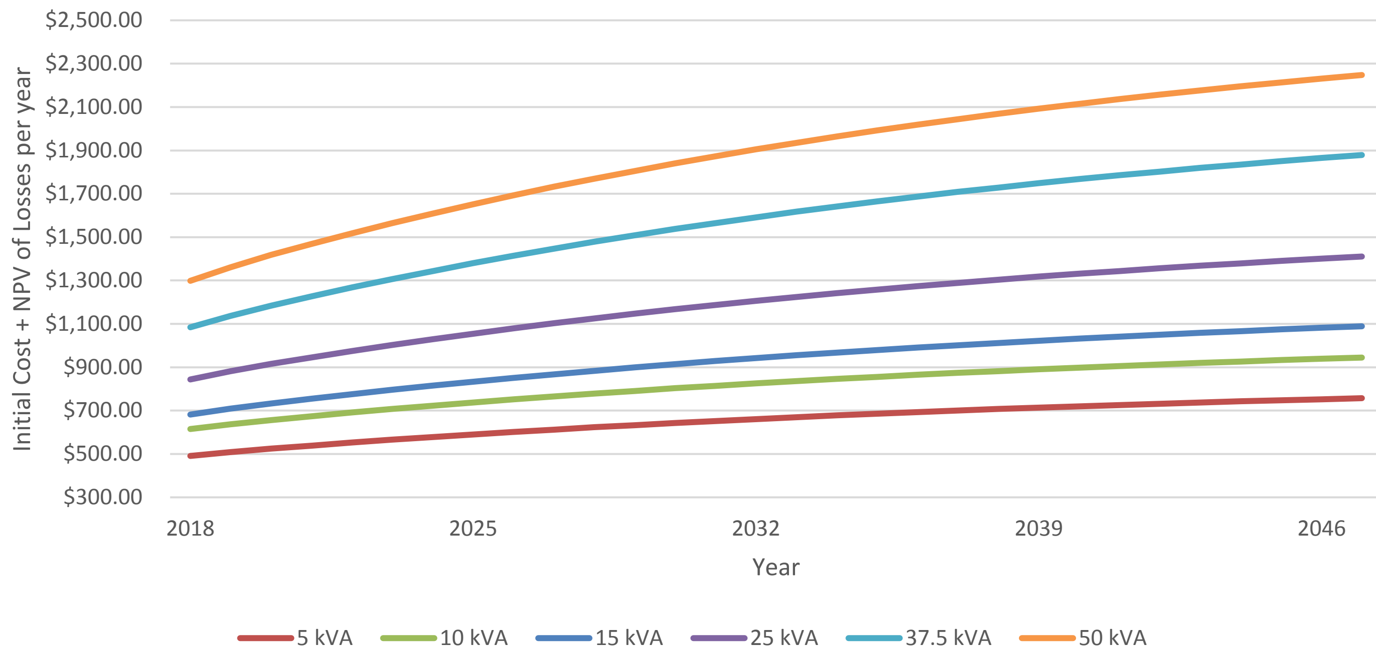



*Figure 4.5.12.C Total transformer ownership cost by year and transformer size over 30 years*

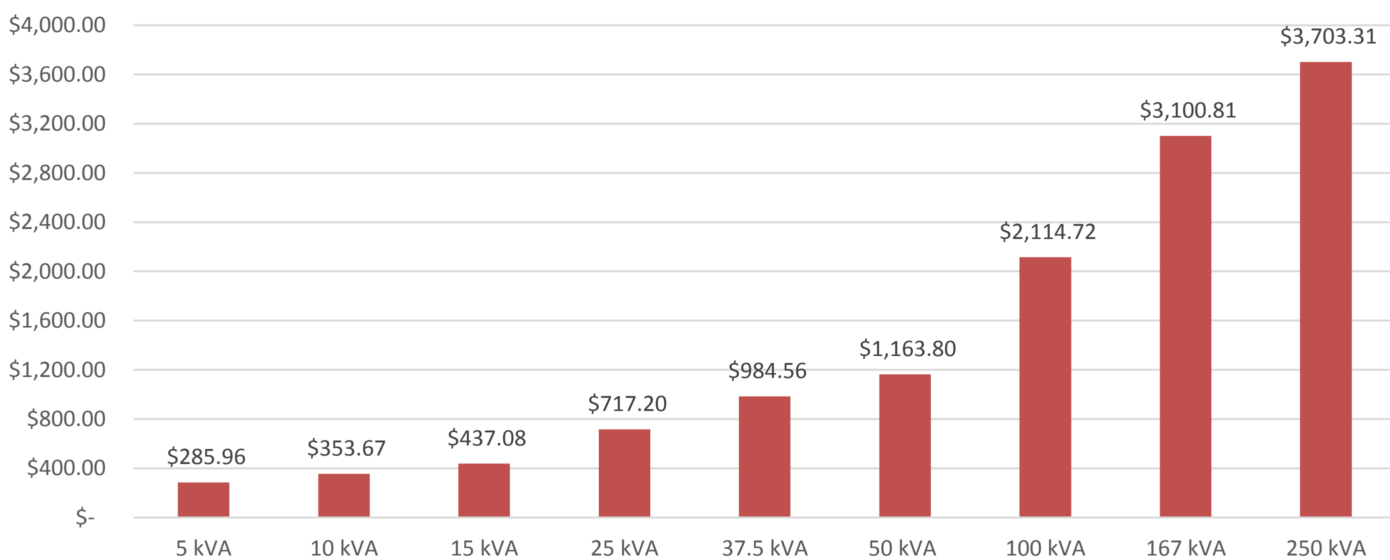



*Figure 4.5.12.D Total transformer losses over 30 years by transformer size*

VEC replaces undersized transformers as soon as concerns are identified; however, we will replace oversized transformers to a case-by-case basis when cost-justified. An hour of lineman time including labor, transportation, and indirect costs is approximately $575. This price does not include the transformer cost and salvage value of the existing transformer.

VEC has seen an increase in overhead and transformer replacement as a result of voltage conversions and underground reconductoring projects. VEC typically replaces transformers due to condition, load growth, or capital projects.

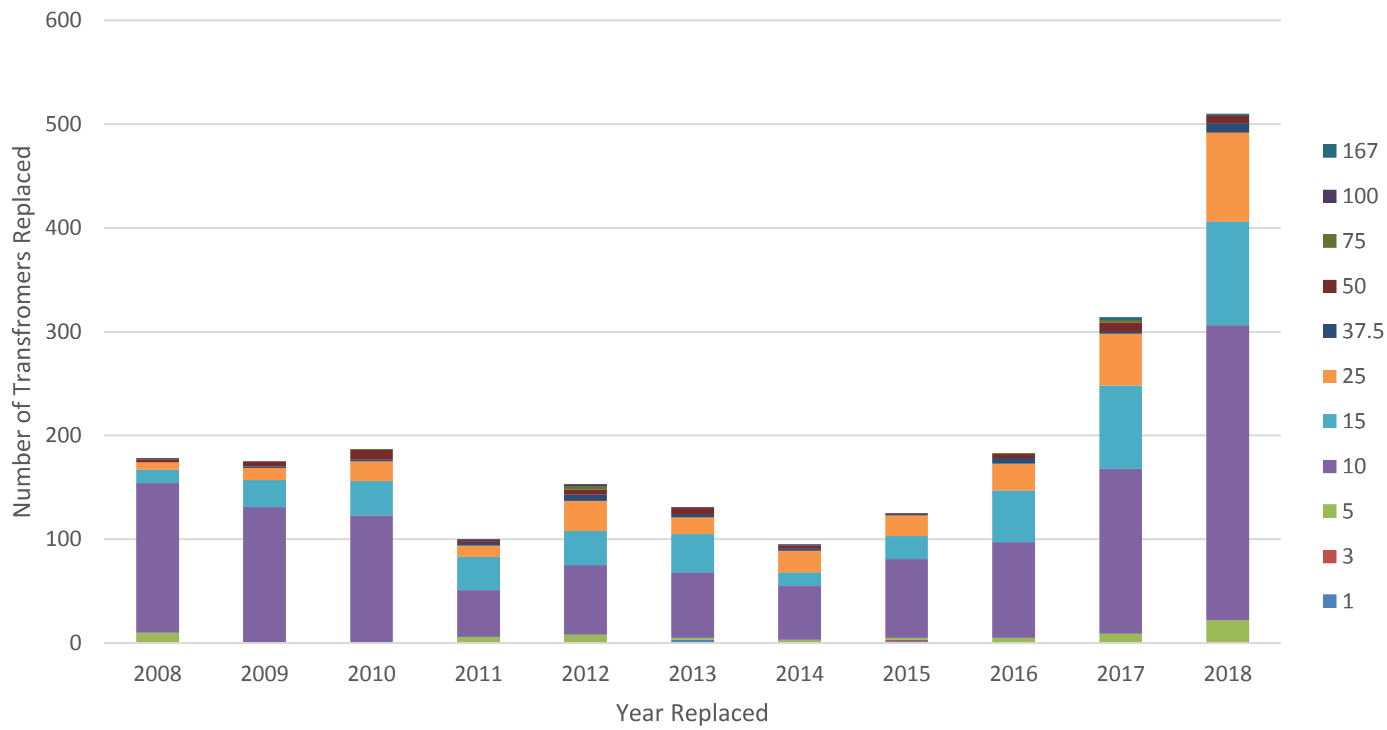



*Figure 4.5.12.E Number of overhead transformers replaced by size (kVA) 2008-2018*

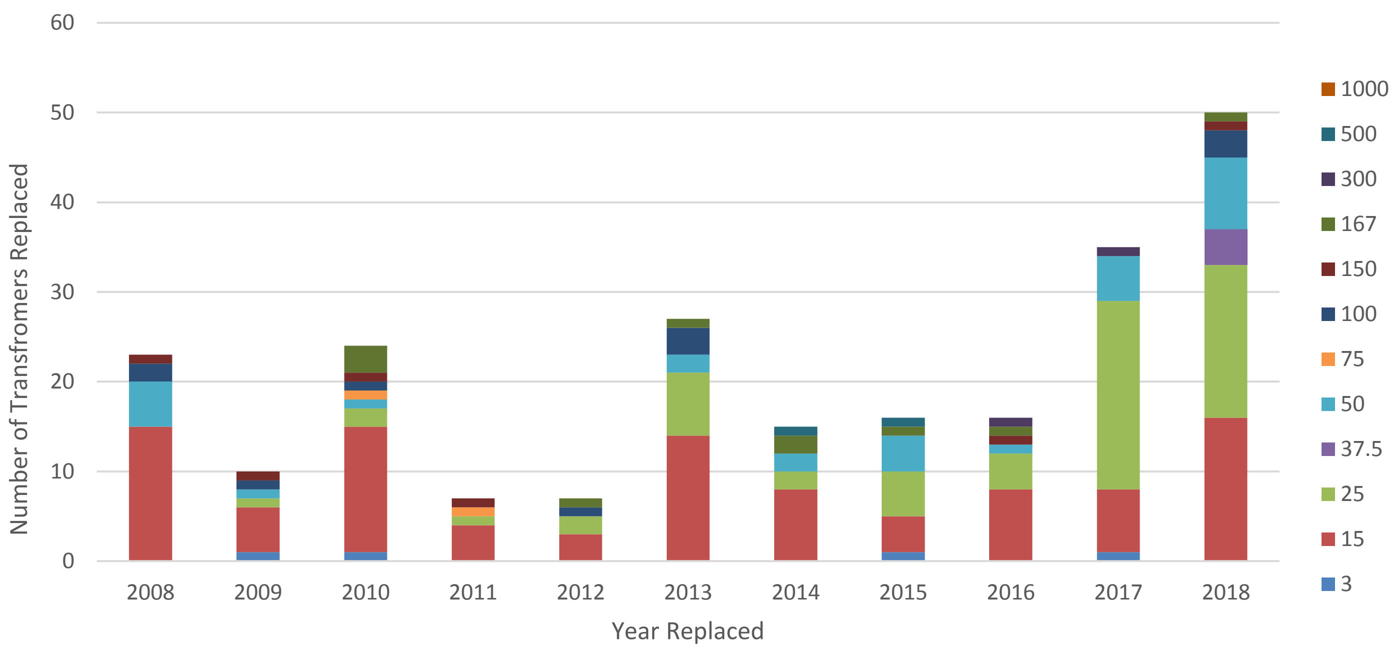



*Figure 4.5.12.F Number of padmounted transformers replaced by size (kVA) 2008-2018*

## Substation Transformers

VEC evaluates substation transformers using the same analytical tool described in the distribution section. The following table shows the initial ownership cost, no load and full load losses, and total ownership cost of four 5/6.25 MVA transformers.

| Transformer | Sell Price | No Load Losses | Full Load Losses | Total Losses | Total Ownership Cost |
|---|---|---|---|---|---|
| ABB 5/6.25 MVA | ***$128,871*** | $37,134 | $17,852 | $54,987 | ***$184,519*** |
| Howard #1 5/6.25 MVA | ***$136,968*** | $35,409 | $12,992 | $48,401 | ***$186,072*** |
| Niagara 5/6.25 MVA | ***$161,916*** | $31,943 | $17,481 | $49,425 | ***$212,172*** |
| Howard #2 5/6.25 MVA | ***$185,000*** | $32,342 | $17,534 | $49,877 | ***$235,827*** |

*Table 4.5.12.A Total cost of ownership, no load, full load, and 30 year losses by transformer manufacturer*

The following graph shows the same information in a different format.

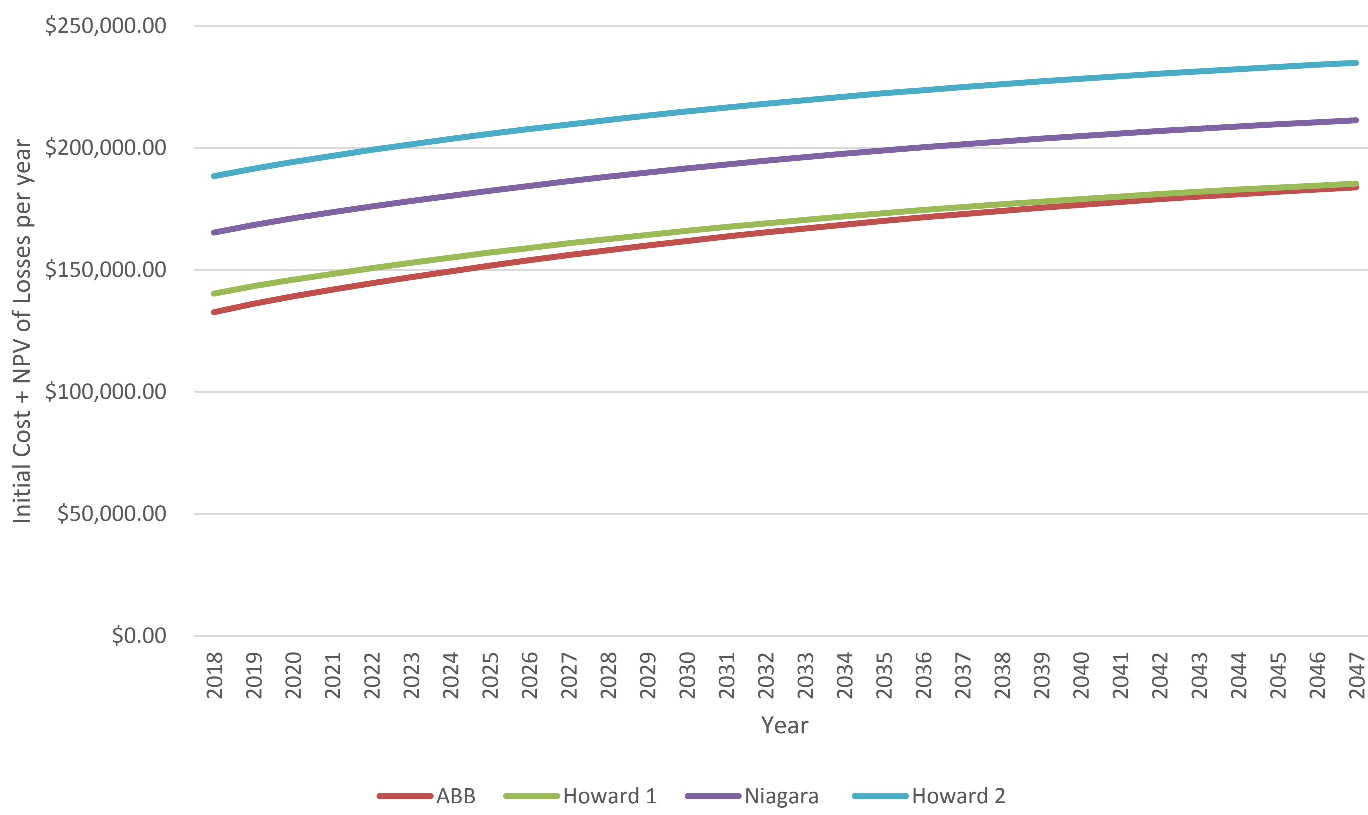



*Figure 4.5.12.G 5/6.25 MVA substation transformer total ownership cost*

Due to the low cost of energy and more efficient transformers, selecting the substation transformer with the lowest initial cost provides the least cost option for the VEC membership.

Substation transformers will be reviewed for replacement once the load exceeds 80 percent of base rating (no fans) MVA. VEC's substation criteria are detailed in further detail in the Appendix-F.

## Overhead Conductor

**Conductor Selection**

Replacement of conductor (wire) generally occurs either because of poor condition or as when needed for load growth or reliability. Loss savings alone generally do not justify a reconductoring project. VEC has recently standardized on the following conductor sizes:

- 1/0 AAAC (Azusa)
- 336 ACSR (Linnet)
- 556 ACSR (Dove)

VEC took into consideration the total ownership costs of conductor upgrades. VEC uses a six-year net present value (NPV) payback period for major investment decisions. VEC calculates losses by multiplying the resistance by the square of the current. VEC models the initial cost of our three conductor standards along with the NPV of six years of losses per mile per conductor given a specific amperage. The analysis utilizes the approximate spot market savings in $/kWh to determine the value of losses. The chart below shows this comparison:

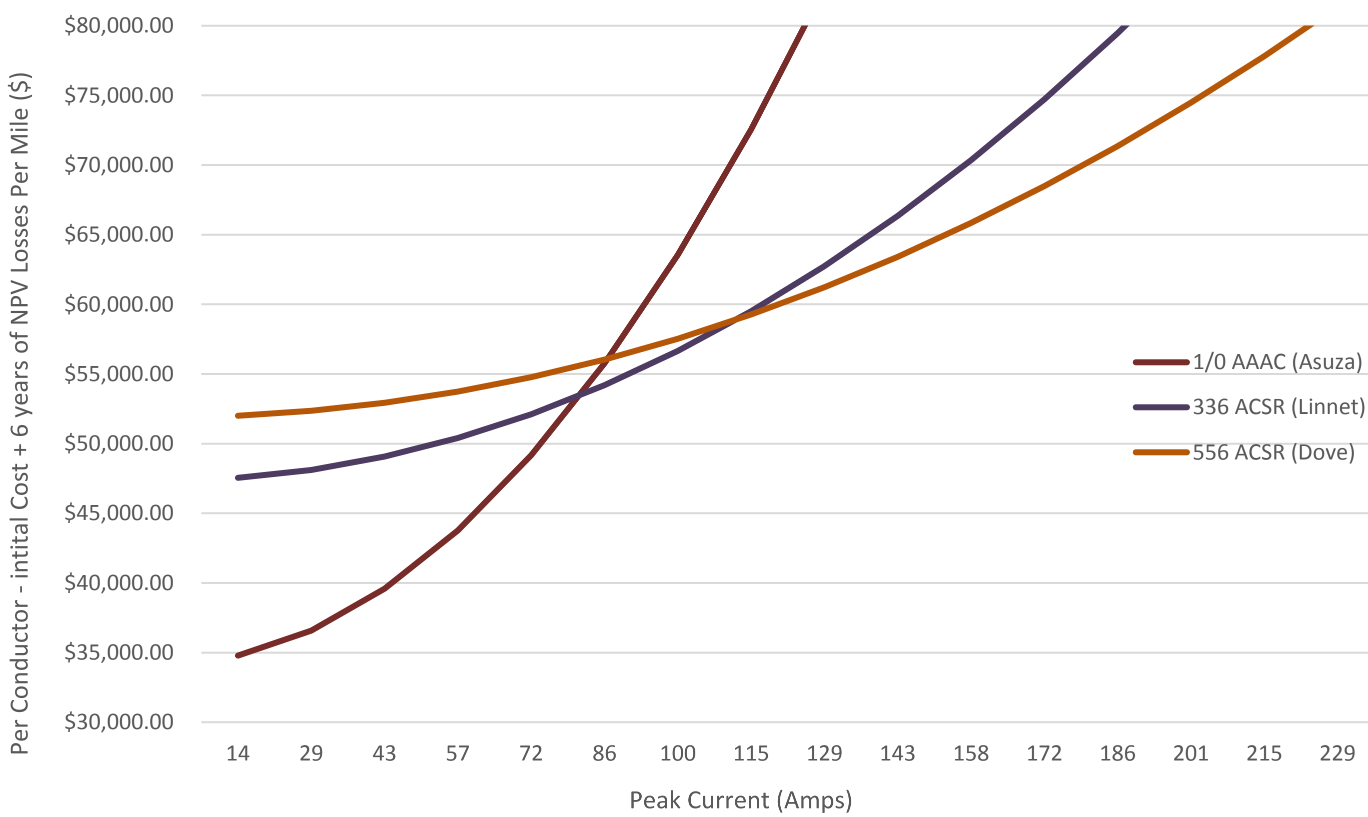



*Figure 4.5.12.H Per conductor initial cost + 6 year losses versus current (Amps)*

From this analysis, VEC developed a wire chart, which is provided in the provided in Appendix-N.

**Use of Covered Conductor ("Tree Wire")**

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

*Figure 4.5.12.I Bare conductor*

*Figure 4.5.12. Covered conductor ("tree wire")*

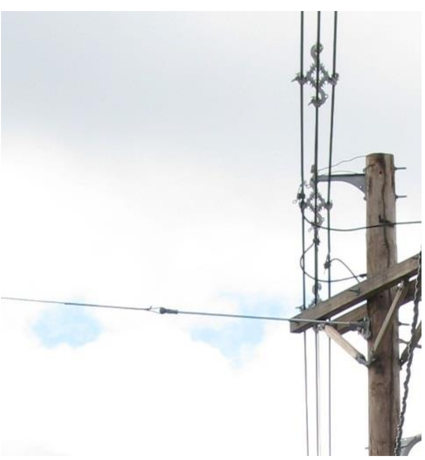


*Figure 4.5.12.J Hendrix spacer cable*

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 and between conductors, but can damage bare conductors and cause contact between conductors, resulting in arcing and sparking. VEC has seen that covered conductor can prevent these types of outages due to the benefit of insulating cable.

In general, covered conductor adds approximately 58 percent to material costs (because it is more expensive and requires shorter span lengths and 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 4-year average for projects that utilize tree wire has been around 36 percent (6.6 conductor miles annually).

**Aging and high loss conductor**

6A Copperweld, #6 Steel, and 8D Amerductor make up approximately 10 percent% (568 conductor miles) of VEC's distribution plant. The vast majority of this conductor is located on single phase lines and their corresponding neutral conductors.

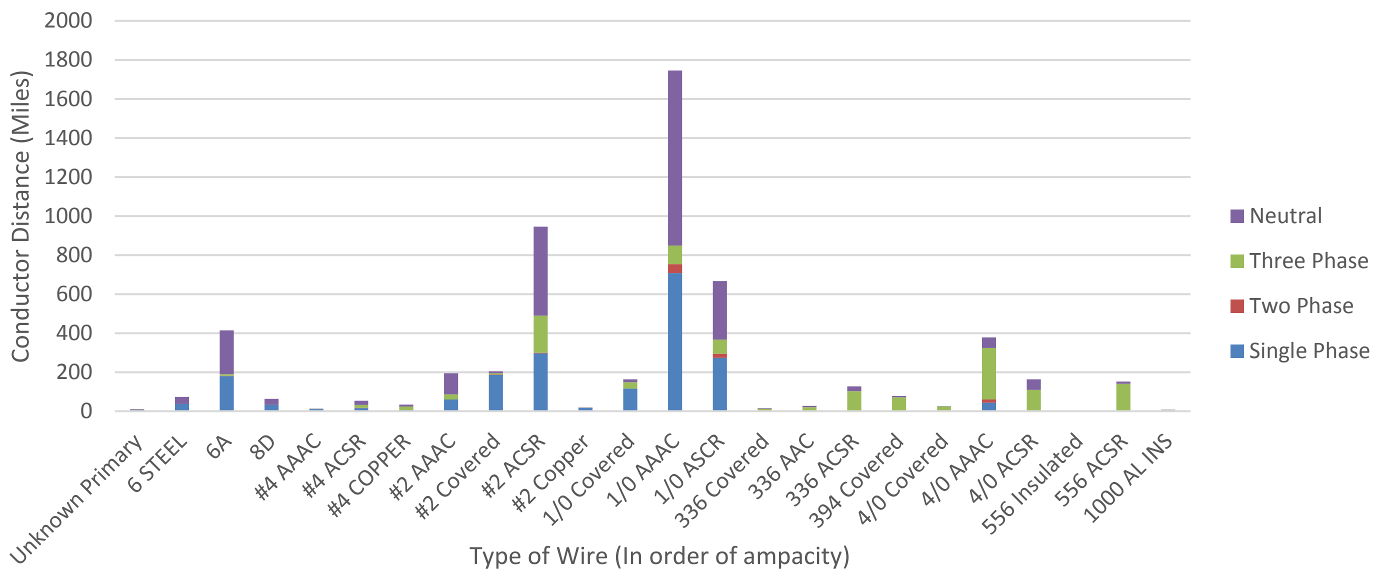



*Figure 4.5.12.K   Miles of VEC overhead distribution conductor by type*

These wire sizes were a common, cost-effective conductor when rural electrification occurred in the early to mid-1900s but are now nearing end of life and in addition are not compatible with present materials and construction practices. As steel wire ages, it becomes hard and brittle, which then becomes a safety issue during repairs since the conductor can break while being handled. As a result, VEC performs work on 8D and 6 Steel after it has been de-energized. The cross-section below is an example of the amerductor wire mentioned above

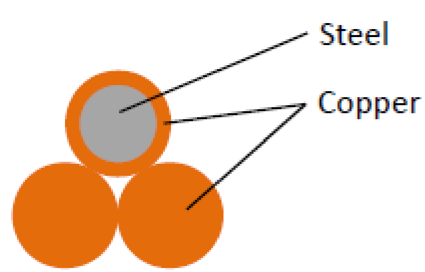



*Figure 4.5.12.L   Cross-section of amerductor wire*

In addition, since resistance increases significantly for small wire, line losses also increase leading to higher operating costs. High losses cause voltage to drop more quickly over a length of line, thereby greatly limiting the amount of load that can be served by that line. This becomes even more important as loads associated with beneficial electrification continue to increase.

Work on these replacements has been slow but is trending in a more positive direction. The 4-year average is 2.6 conductor miles.

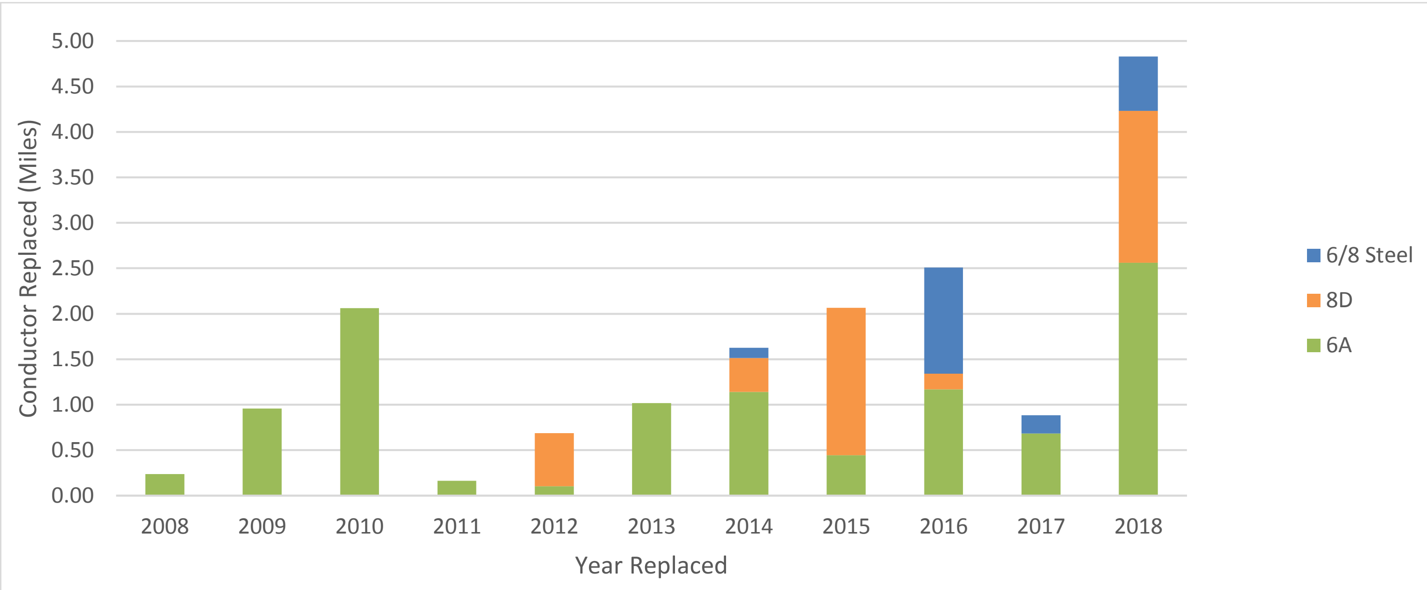



*Figure 4.5.12.M Miles of undesirable conductor replaced 2008-2018*

## Underground Conductor

An overhead line is considered a best utility practice from an overall power system installation and operating cost perspective. Overhead lines allow for flexibility such as the ability to add phases, to upgrade conductors due to overload, identification of faults or damage, to convert to higher voltages, to add secondary services, and to provide VAR support by adding capacitors and voltage regulators, all of which help manage the overall design and operation of the power system.

However, approximately 78 percent of VEC's new line extensions are underground primarily due to aesthetic preferences on behalf of VEC members. While aesthetic and reliability benefits exist for undergrounded systems, underground cable has a greater impedance and voltage drop than overhead cable due to trapped conductor heat and magnetic coupling. Underground cables have more power losses due to heating and the lack of cooling within the conduit itself (unlike that of an overhead conductor that is cooled by the temperature and movement of the surrounding ambient air). For this reason, larger conductors are needed for underground cables versus overhead conductors to serve the same load levels.

**Construction Practices**

Proper installation of underground requires the following:

- Conduit
- Jacketed EPR (ethylene propylene rubber-insulated) Cable
- Burial and installation

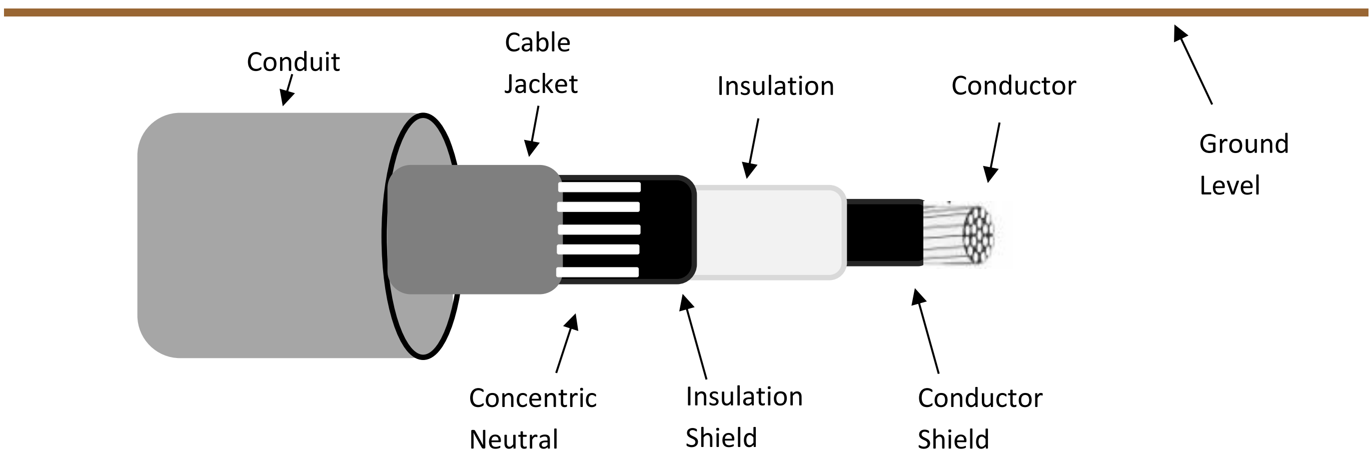



*Figure 4.5.12.N VEC standard installation of underground conduit and conductor*

**Direct Buried Underground**

While the above installation is VEC's standard today, direct buried underground cable was common practice in the 1970s and earlier.

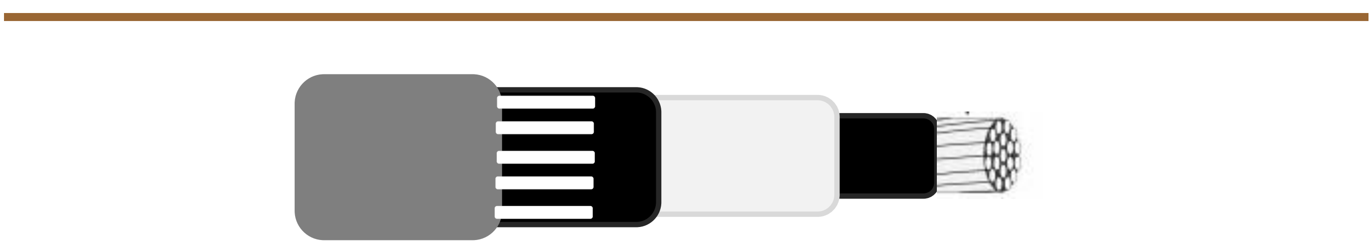


*Figure 4.5.12.O Direct buried underground installation*

Direct buried cable is not in conduit and can be more susceptible to failure.

**Unjacketed Cable**

In addition to direct buried cable, VEC has also found several locations where unjacketed cable was used and the concentric neutral had become separated from the cable. This makes locating a fault extremely time consuming and can cause longer outages.

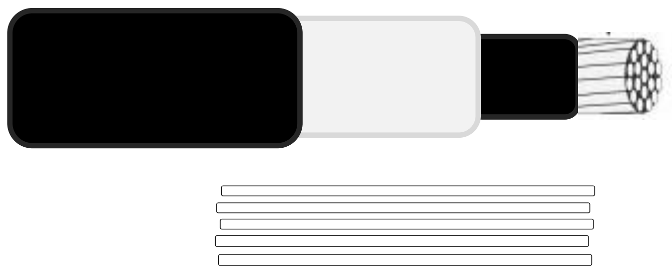


*Figure 4.5.12.P Figure 4.5.12.Q Unjacketed cable underground installation*

VEC has an unknown quantity of both direct buried and unjacketed cable on its system and is not actively replacing locations simply due to this type of installation. However, VEC is in the process of determining the construction type of all of its underground as part of its Maintenance plan initiative.

**Reliability of Underground Conductor**

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 an overhead outage. The figure below compares our outage experience for overhead an 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 4.5.12.B Reliability of underground conductor*

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

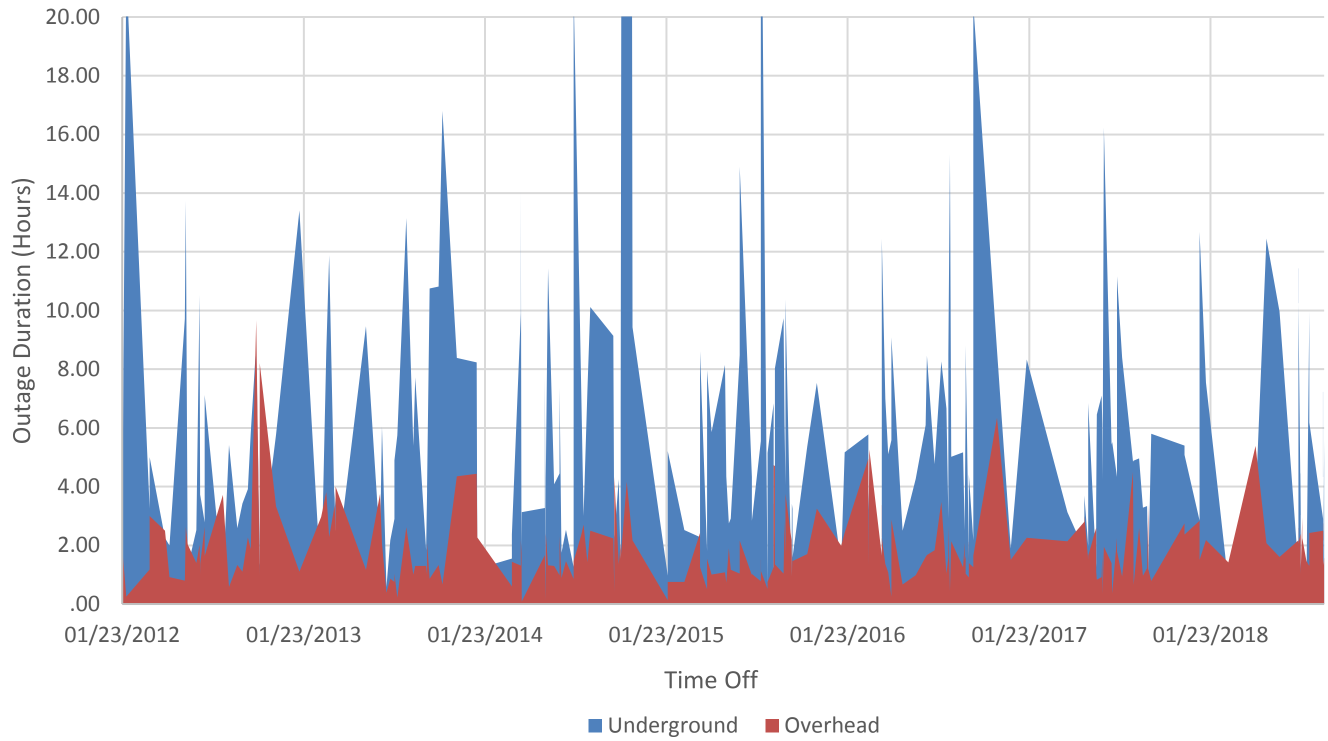



*Figure 4.5.12.R Underground versus overhead outage duration (2012-2018 data)*

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 takes particularly long to restore because new conductor cannot be pulled into existing conduit. As a result, all new VEC and member installed underground are required to have conduit.

**<u>Underground Conductor Cost (12.47 kV Distribution)</u>**

In VEC's service territory, on average a 12.47kV underground distribution line costs approximately two to three times the cost of an overhead pole line, due mainly to the increased labor and indirect costs required to install the conduit and drainage systems as well as cable pulling and equipment vaults. However, VEC has seen costs of overhead construction increase over the last ten years that has reduced the cost difference.

As construction complexity increases (multiple phases, areas of high load growth, directional boring), or the project involves difficult soil (ledge or rock), the cost of underground can increase to five to six times the average cost of an overhead line. VEC is currently reviewing alternative underground construction (cable in conduit via plow) that may yield underground construction cost savings.

Depending on the choice of underground cable and conduit, the life expectancy of an underground line is about half that of an overhead line, requiring more frequent replacement. On the other hand, vegetation maintenance and outage restoration costs are less for underground versus overhead.

## Poles

**Distribution**

VEC has over 58,000 distribution poles on its system, the vast majority of which are treated with Pentachlorophenol, more commonly referred to as Penta. All of VEC's poles are manufactured following American National Standards Institute (ANSI) and American Wood Protection Association (AWPA) guidelines to ensure the desired size, strength, material quality, original treatment loadings and decay resistance properties. From a depreciation perspective, the average pole life expectancy of a utility distribution pole is considered to be 30 years; however, with proper maintenance, including inspection and treatment, life expectancy can exceed 60 years. VEC replaces poles when their condition requires it, assuming they meet clearances (height) or mechanical (tension/weight) requirements. VEC uses 60 years as a guide for asset planning, but will not replace a pole that an inspection shows is still structurally solid just because it reaches 60 years old.

In fact, approximately 3,300 of VEC's poles are over 60-years old. VEC's average distribution pole manufactured age is 1988 (31 years old). The chart below shows the number of VEC distribution poles by manufacture year using a sample size of 41,606 poles.

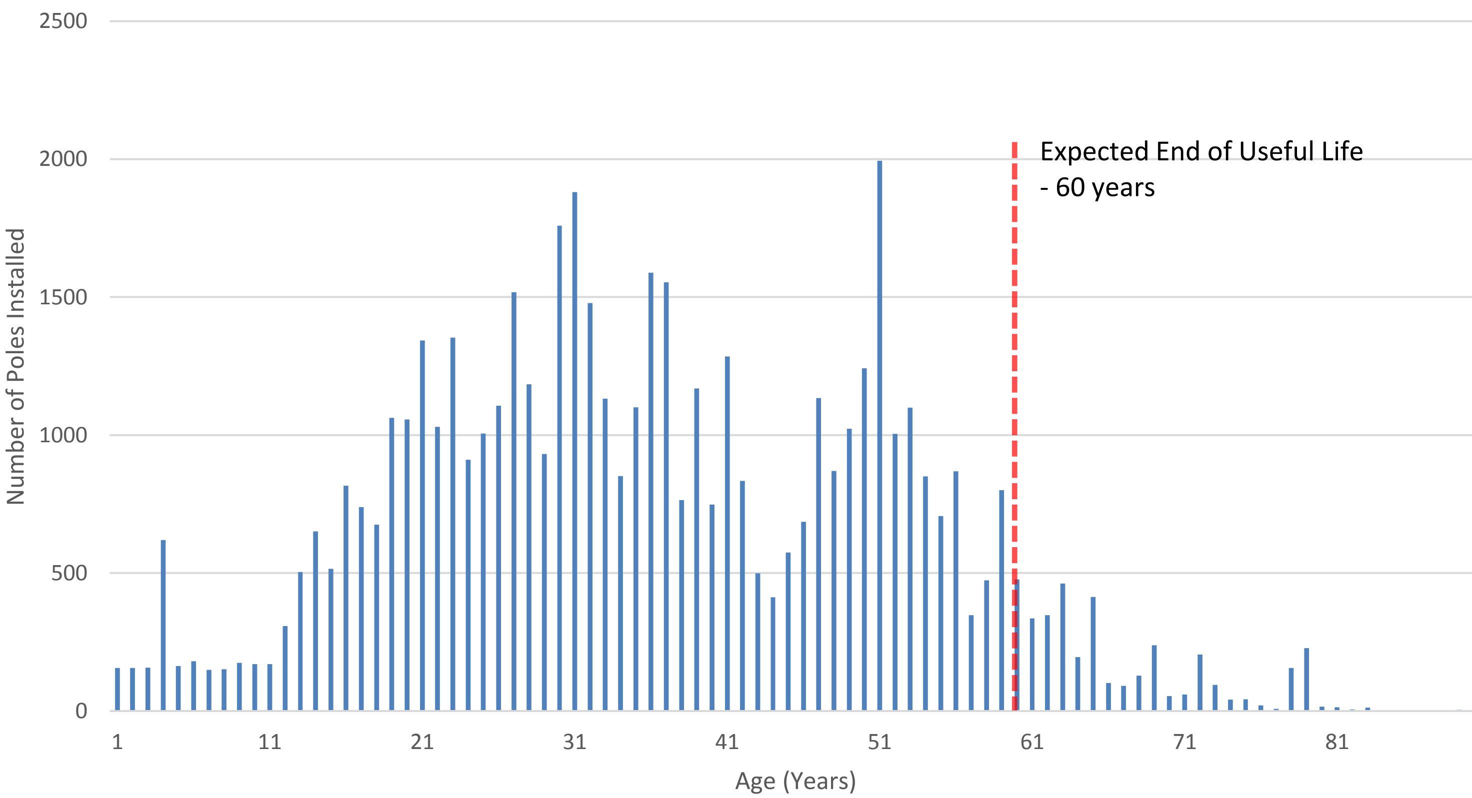



*Figure 4.5.12.S Distribution pole assets by manufacture year*

VEC has a pole inspection and treatment program that assesses the condition of the poles. (For more information see the Maintenance section of this document.) Over a 7-year period (2010-2018), VEC has rejected on average 1.46 percent of its poles. The average age of rejected poles is 57 years old (manufactured in 1962).

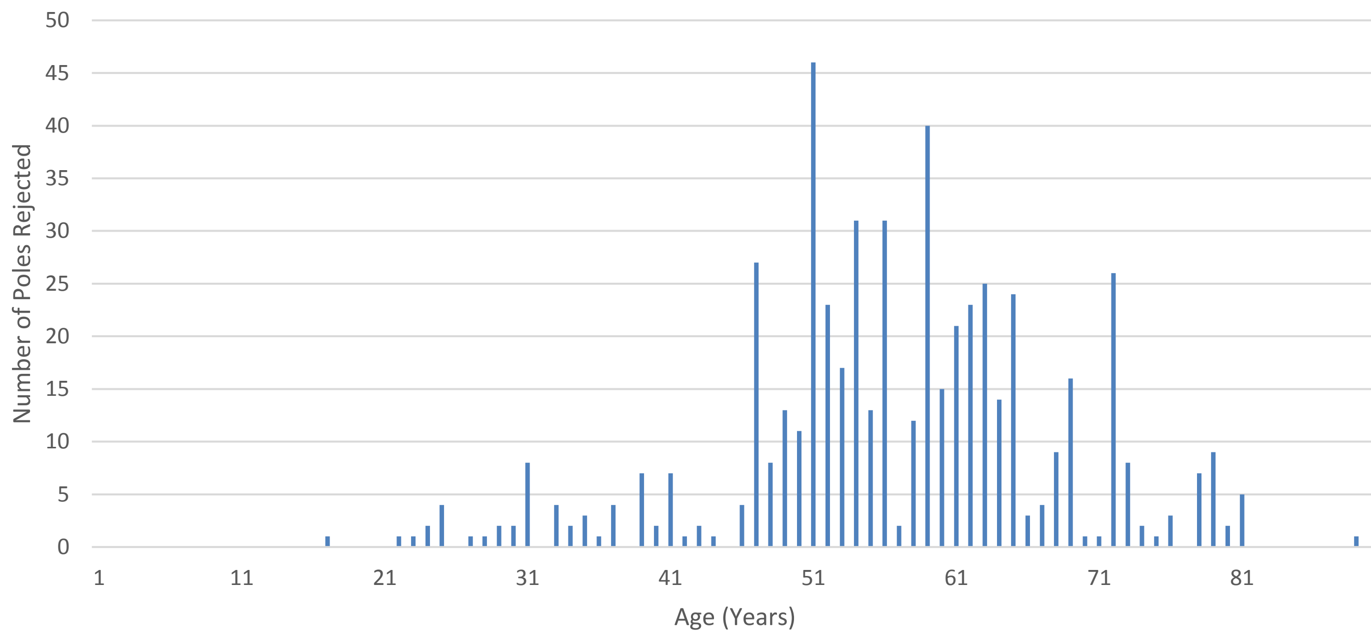



*Figure 4.5.12.T Distribution pole rejects by manufacture year*

The chart above indicates that poles that are younger than the average rejected age poles (57 years) are less likely to be rejected. The poles at or older than the average reject age are more likely to be rejected as they are more likely to have not been maintained since they were installed. VEC is almost through its first pole inspection and treatment cycle, which we expect should guarantee another 10 years of asset life; VEC's remaining poles should last several decades beyond the rejected age of the first cycle.

While most pole rejections identified during the pole inspection program are as a result 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.

VEC follows Appendix 1 of the Best Management Practices (BMPs) documented in PSB Docket No. 8310 associated with the use of Pentachlorophenol-treated utility poles in Vermont.

Each year since 2008, VEC replaced an average of 440 poles due to changes in use or the results of the annual pole inspection program. The pole inspection program has identified around 100 deficient poles annually. The chart below shows the height (in feet) and quantities of poles replaced since 2008.

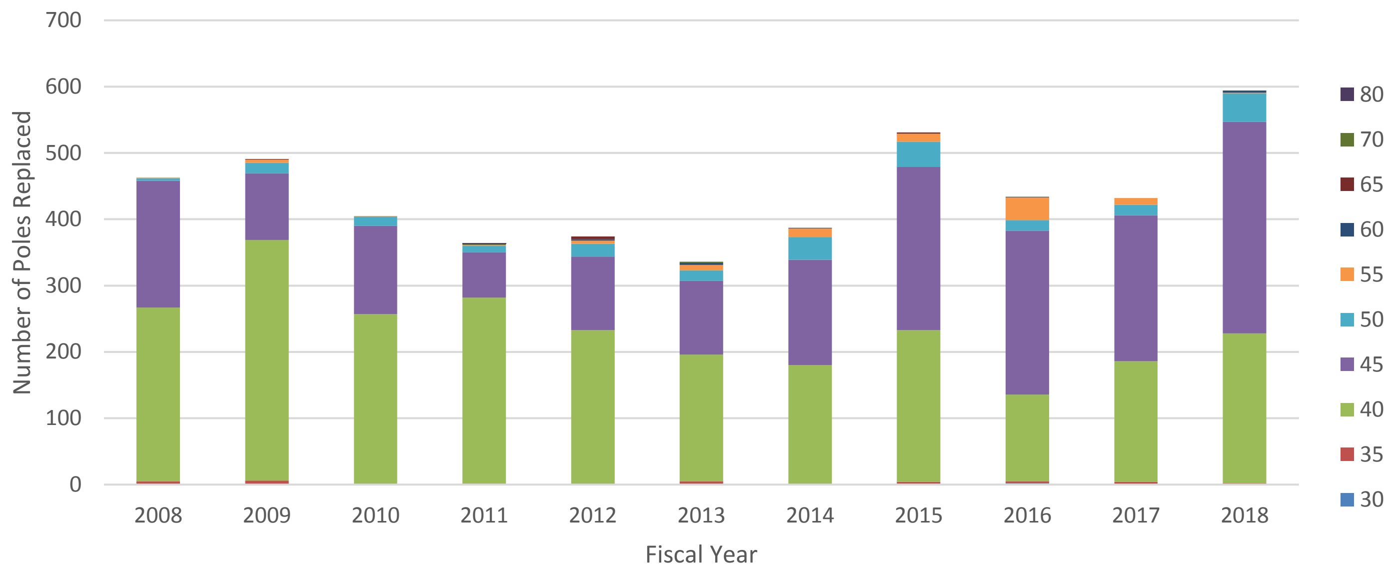



*Figure 4.5.12.U Number of VEC poles replaced by height 2008-2018*

At this rate, VEC is replacing approximately one percent of its pole assets annually; at this rate it would take approximately 100 years to replace all of its poles. VEC expects the quantity of pole replacements to increase in the future as VEC increases spending on reconductoring projects (requiring mid-spans and pole replacements), new construction (additional phases), and line relocations.

**<u>Telephone Pole Replacements</u>**

Telephone pole replacements refer to any pole replacement within Franklin Telephone and Consolidated Communication's joint owned set area or at the request of Consolidated or Franklin Telephone. VEC replaces around 200 of these poles annually and expects this number to decrease in coming years due to VEC's 2019 acquisition of 7,700 joint owned poles from Consolidated. However, given this acquisition, VEC's non-telephone pole replacement budget (reference above) has increased (around $130,000) because of VEC now setting and removing those poles.

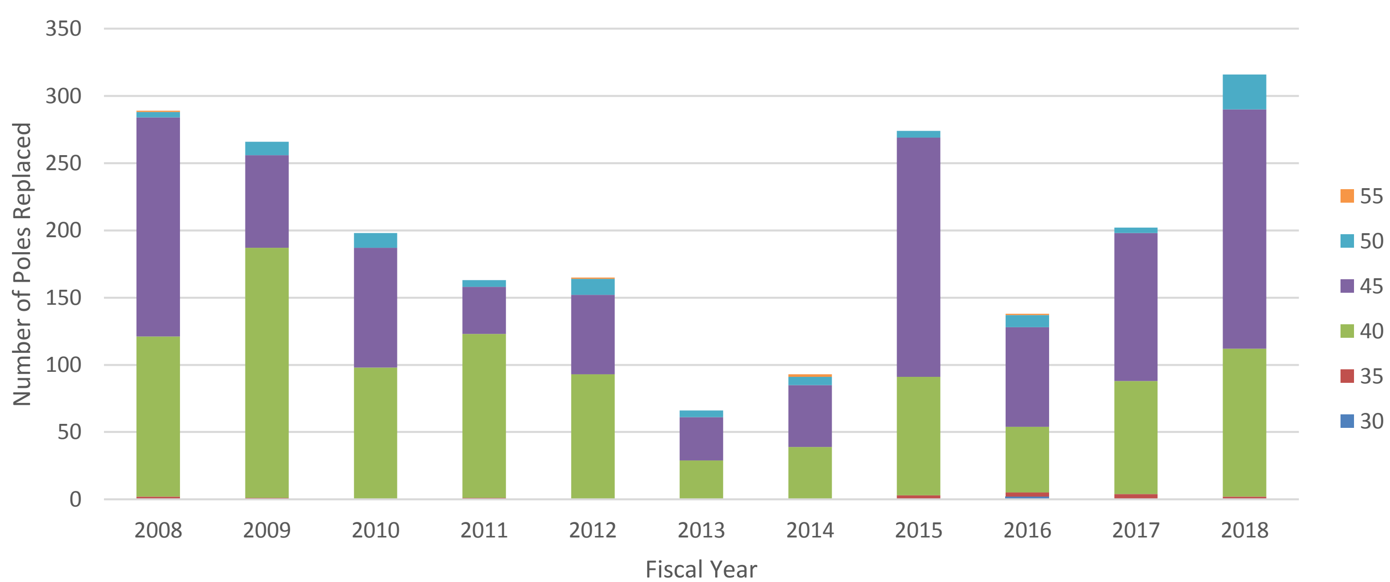



*Figure 4.5.12.V Number of telephone poles replaced by height 2008-2018*

**Transmission**

VEC has over 2,100 transmission poles on its system with around 470 poles (23 percent) older than 60 years. The average transmission pole manufacture year is 1981 (making the average pole 38 years old) with the oldest poles being on the H16 line (Barton Tap-to-Irasburg).

VEC completed a transmission pole inspection of all transmission poles in 2009 that yielded a reject percentage of less than 0.5 percent. The inspection found only three rejected poles and the average reject pole age was 51 years old. As with VEC's distribution poles, the vast majority of pole replacements completed outside of the inspection program are due to the condition of the pole top due to decay from water ingress. The chart below displays quantity of VEC transmission poles by manufacture year using a sample size of 2,032 poles.

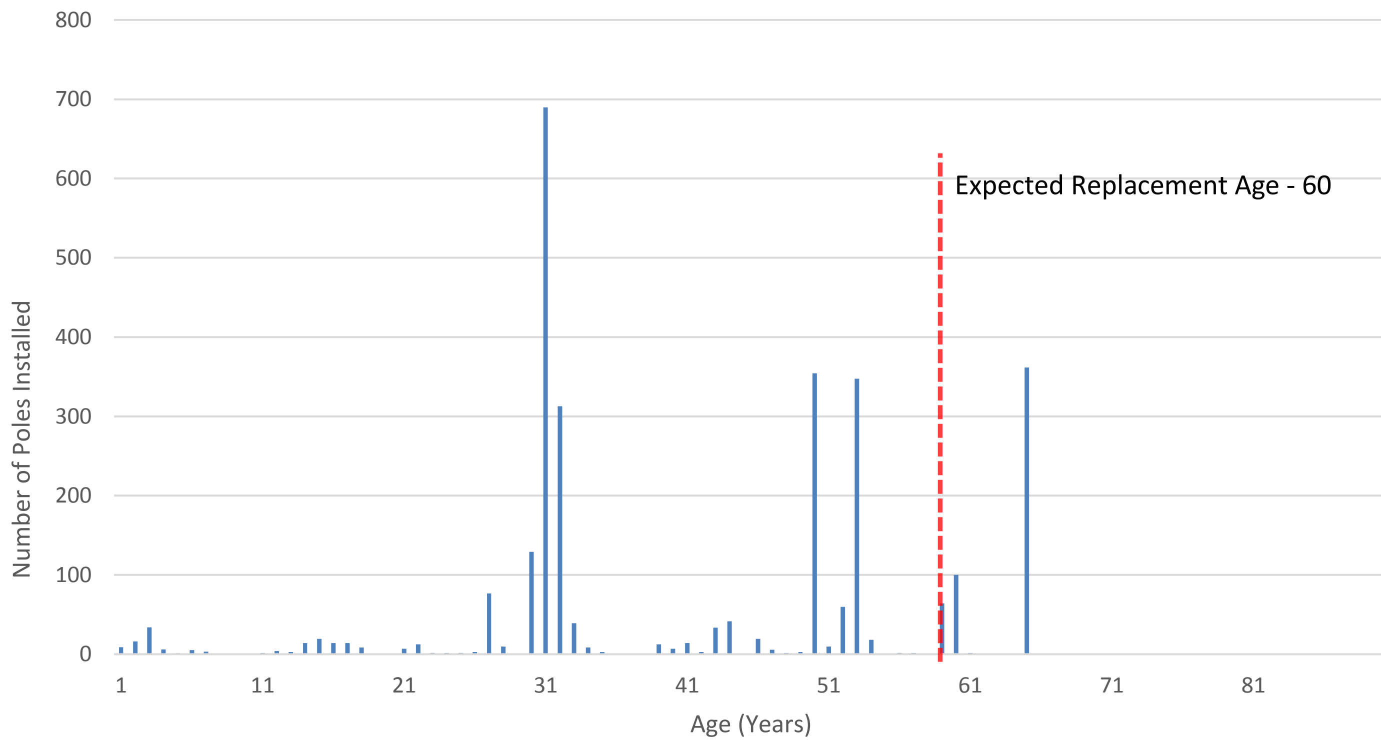



*Figure 4.5.12.W  Transmission pole assets by manufacture year*

## Material Cost Increases

VEC has seen significant cost increases because of recently implemented trade tariffs. These costs on average have represented a roughly seven percent increase from 2017 to 2018 and have affected everything from crossarms to wire to minor materials such as brackets. These increases will have an effect on VEC's pole replacements and ordinary replacements annual blankets that are discussed further in Section 5 - Action Plan.

### 4.5.13 T&D Capital Project Prioritization

In 2017, VEC developed a capital prioritization process for all T&D projects. This process, which VEC updates annually, takes into consideration components such as economic payback, impact to reliability, number of members, size of loads, and safety considerations. The process is as follows for all projects:

- T&D capital projects are identified from studies, maintenance procedures, and outside entities such VAOT or other electrical utilities.
- VEC enters each project into an internal VEC database and places it through the prioritization process.
- Reviews occur with the appropriate stakeholders involved in the project (Engineering and Operations) and an overall value is assigned to each project
- A capital budget target is developed, and projects are chosen based on their ranking, resource planning, and time constraints. For instance, some projects may require permitting or easement acquisition. In other cases, there may not be adequate internal resources available to accomplish the work.

A chart of the ranking scheme is provided below along with an explanation of each metric and adder.


*Figure 4.5.13.A VEC T&D capital project ranking scheme*

## Initial Metrics

VEC reviews each project for seven initial metrics, which make up an initial ranking:

- Reliability – VEC gives higher priority to projects that reduce outage frequency and outage duration on both the worst performing circuits and sections of line on three or more reports.
- Deliverability – This metric takes into consideration both the number of members as well as the load used. Higher priority is given to T&D projects that affect more load and/or more members.
- Condition – Higher priority is given to T&D projects to address conditions that do not meet standards or have a high severity (high impact).
- Contingency – This measures the ability of a project to reduce restoration times or otherwise improve the operability of the system by reducing planned outages for maintenance and other switching operations. Projects that add feeder backup or add a tie would receive a higher ranking on this metric.
- Accessibility – VEC gives higher priority to projects that improve accessibility to locations with poor/no accessibility in normal and extreme weather.
- Long Term Goals – VEC has identified four long term T&D goals and ranked them in priority
    1. Building tie lines
    2. Reconductoring or underground replacements
    3. Relocation of lines from off-road ROWs to the roadside
    4. Reliability improvements via sectionalizing
- Strategic Goals – Each year VEC puts together a strategic plan, which lists certain goals/targets; VEC gives priority to T&D projects that help meet these goals/targets.

VEC weights these initial metrics with the following values:

| Weighting | Value |
|---|---|
| **Reliability** | 20 |
| **Contingency** | 20 |
| **Deliverability** | 15 |
| **Condition** | 15 |
| **Accessibility** | 15 |
| **Long Term Goals** | 10 |
| **Strategic** | 5 |

*Table 4.5.13.A Initial metric weighting values*

## Non-Discretionary Adder

The non-discretionary adder exists to prioritize certain projects above all others. The value for this adder will be either 0 or 100. If a project meets one of the following criteria it is automatically rated ahead of any discretionary project:

- Regulatory (VAOT, FairPoint IOP, NERC, PUC, Tier 3 Projects)
- Code Violations (NESC, IEEE, ANSI)
- Load Growth – member service
- VELCO Projects

## Shovel Ready Adder

To account for projects that may have already been designed, for example multiyear projects, the following "adders" are available:

| Value | Description |
|---|---|
| **10** | Project fully designed and or staked |
| **10** | Project permitted (VAOT, CPG, etc.) |
| **10** | Material has been installed or purchased |
| **10** | Agreement in place (Joint Ownership or other) |
| **10** | Multi-Year Project |
| **50** | Net present value (NPV) payback period of less than six years |

*Table 4.5.13.B Shovel ready adder table*

Once this prioritization process is completed, we review the information with the appropriate stakeholders involved in the project (Engineering and Operations). A capital budget target is developed, and projects are chosen based on their ranking, resource planning, and time constraints.

### 4.5.14 New Services

VEC installs around 270 new services each year, the vast majority of which are small 100 or 200 A services. Three categories make up the approximate annual peak power (kVA) of all new services from 2015-2018:

- 50 percent residential (~2000 kVA)
- 37 percent sugar making load (~1600 kVA)
- Remaining 13 percent is commercial load (~575 kVA)

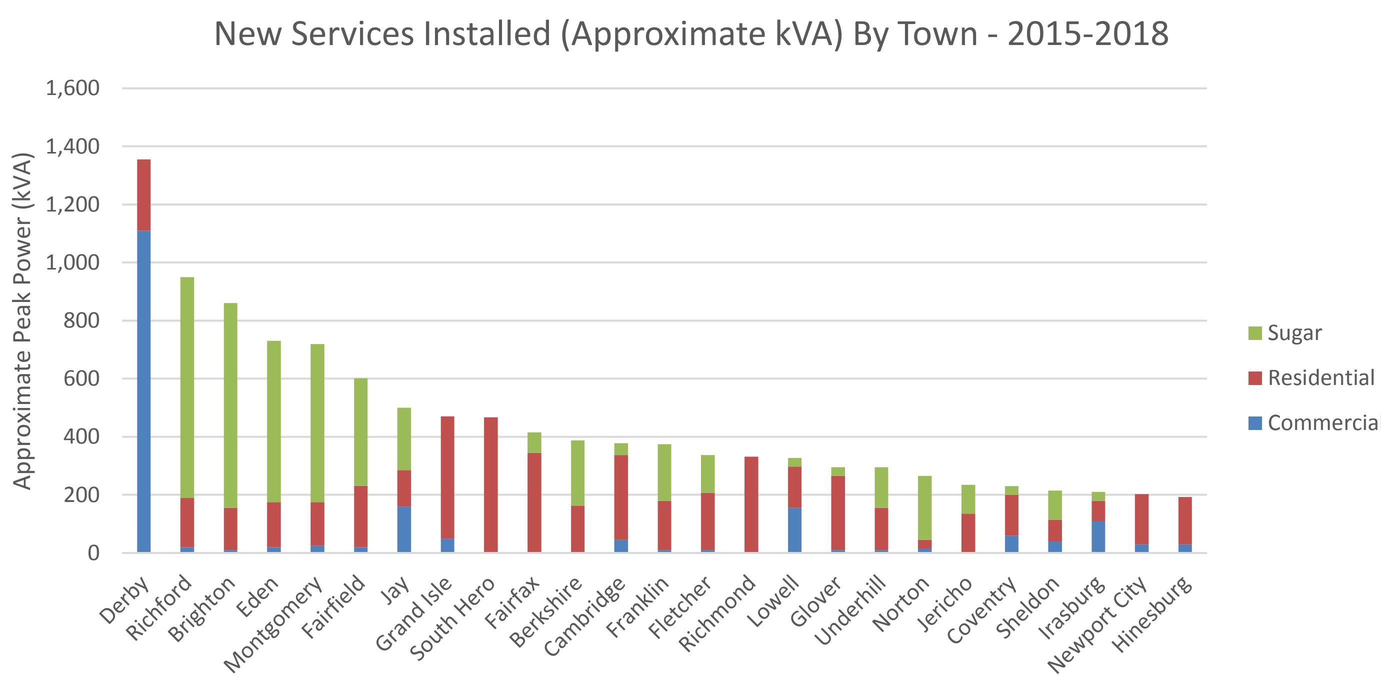



*Figure 4.5.14.A New services installed (approximate kVA) by town - 2015-2018*

## 4.6 Grid Transformation and Technology

### 4.6.1 Distributed Generation

Distributed generation includes all generation that is connected to VEC's distribution system and generally located behind the meter and owned by a member or a developer. Distributed generation is often grouped into a larger subset of resources called Distributed Energy Resources (DER) which also includes energy storage and other controllable resources.

VEC continues to see a dramatic rise in distributed generation on its electrical system, largely driven by technology availability and federal and state incentives. Distributed generation projects generally fall into one of three categories formats: net-metering projects, independent projects developed pursuant to Power Purchase Agreements (PPAs) with VEC, and Standard Offer projects. The chart below shows total nameplate (AC) generation of all active projects on VEC's system since 2008:

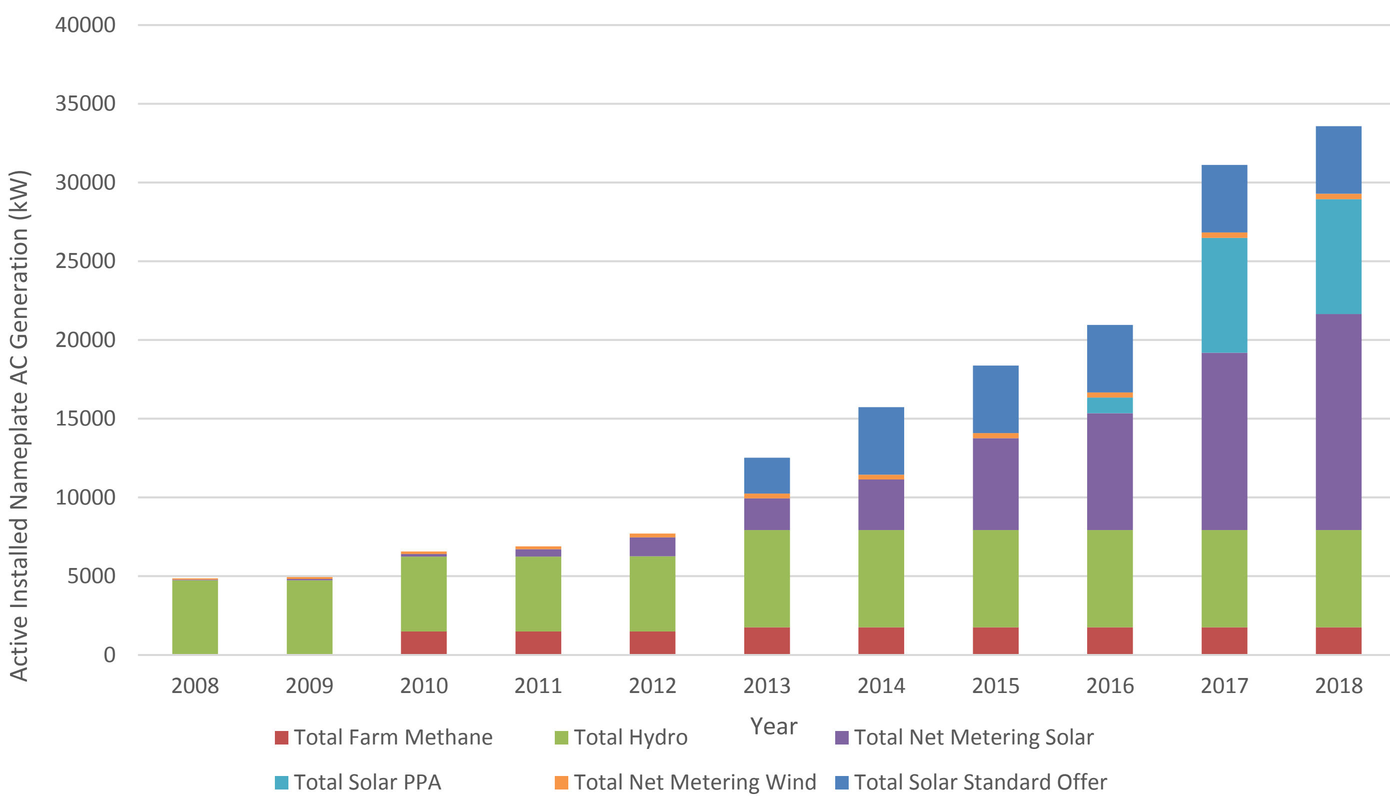



*Figure 4.6.1.A Increase in installed distributed generation since 2008*

VEC currently has 33.5 MW of distributed generation installed on its system (13.7 MW of which is net-metering solar).

#### Net-Metering

VEC has seen a rapid increase of the amount of net-metering solar on its distribution system. Of the 13.7 MW total net-metering solar, larger net-metering projects 150kW and above (group-net metered) make up 28% (~4MW). Around 8.2 MW of solar is pending, with the vast majority (6.5MW) being group net-metering projects. These larger interconnections generally have a bigger impact to VEC's distribution system and may cause constraints. In the event that VEC identifies a constraint, the generation project developer is responsible to pay for the system upgrade per current PUC rules.

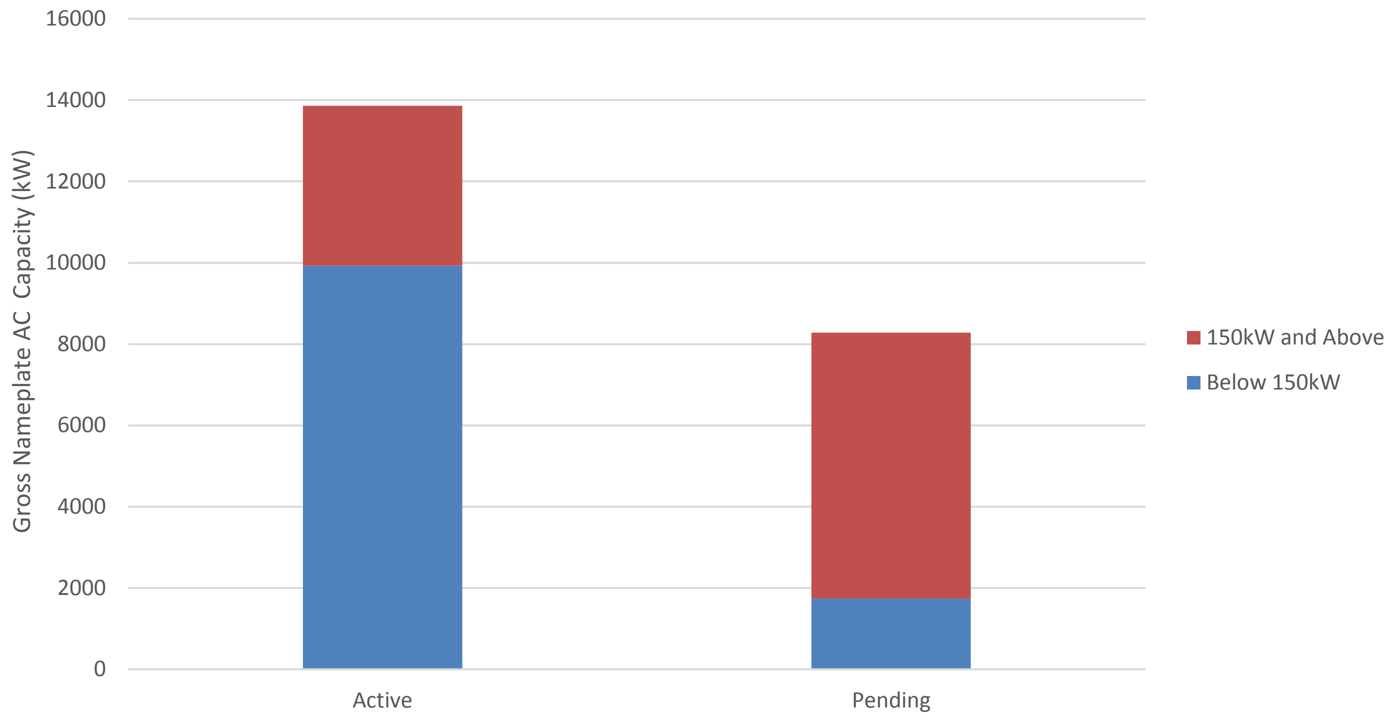



*Figure 4.6.1.B Active and pending net-metering by size*

VEC closed its queue to new net-metering projects in early 2015 due to regulatory limits and then reopened its queue in 2017. Since 2017, VEC has seen around 380 applications annually.

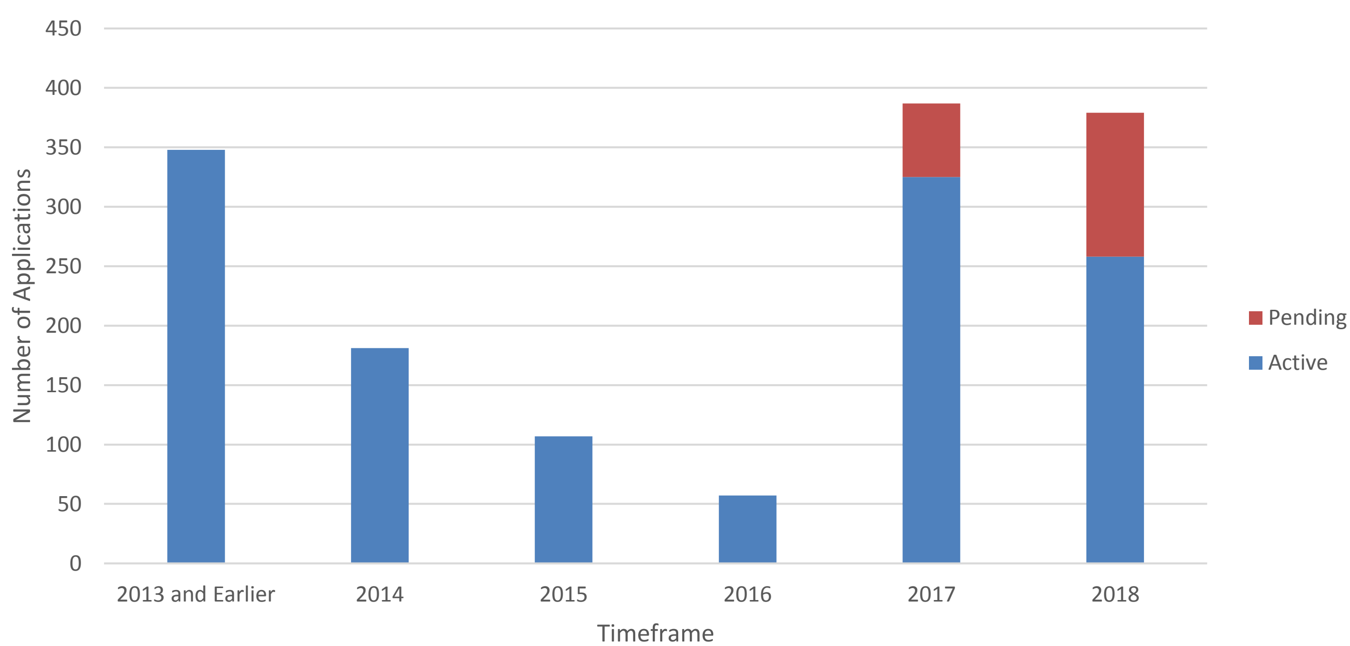



*Figure 4.6.1.C Net-metering applications by year*

Residential projects, which VEC classifies as 15 kW and under, have been primarily located off of substations in Grand Isle, Chittenden, and Franklin Counties with the town of Hinesburg representing the largest quantity. The figure below which shows these residential projects by substation is also available in Appendix-U.

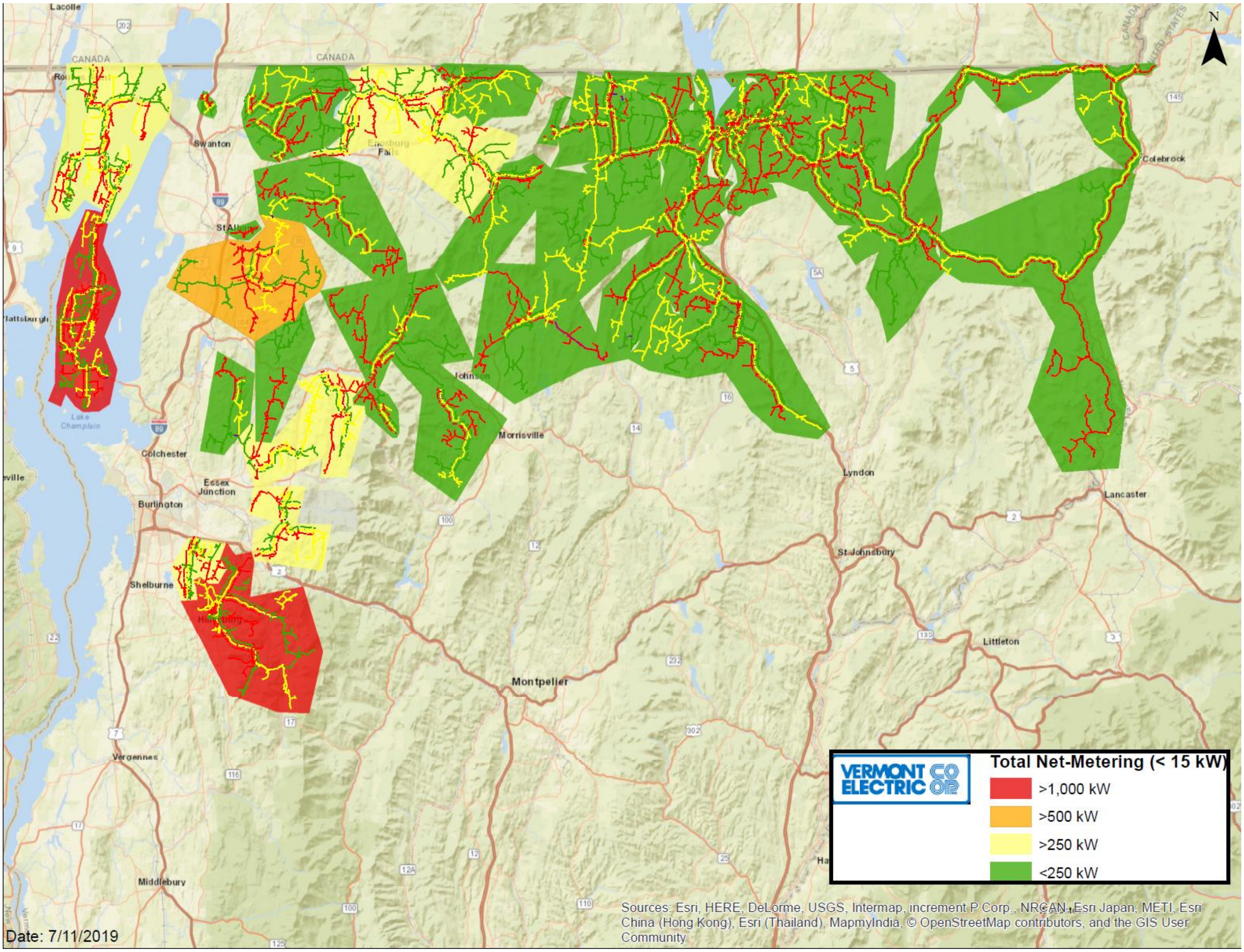



*Figure 4.6.1.D Total net-metering (<15kW) by substation*

## Grid Impacts

All generation projects are required to obtain a Certificate of Public Good (CPG) from the Public Utility Commission (PUC) in order to interconnect to VEC's system. VEC reviews every generation interconnection and, when required by PUC Rule 5.500, performs a Fast Track Screening and System Impact Studies to ensure that generators are interconnected to the system safely and reliably. VEC's Interconnection Guidelines can be found online on VEC's website. They provide developers with information on the interconnection process, equipment requirements, application instructions, screening criteria, and service extensions.

While the increased penetration of distributed generation onto the system presents challenges to planning and operation of the system, there are potential solutions for each of these challenges. The challenges and solutions are identified below:

- Impacts to Feeder Backup: If the feeder with a large generator is being tied to and sourced from a feeder further from the source, the voltage rise can exceed the top of the acceptable voltage range. *This issue is identified in VEC's Fast Track Screening of the project and a typical solution is to install larger line conductors to reduce source impedance or to add strategically placed line voltage regulators to buck the high voltage. However due to the cost implications of both of those solutions, VEC will typically request the generator go off-line while the feeders are tied.*

- Islanding: Islanding occurs when the grid is disconnected and a distributed generator continues to provide power and backfeeds into the grid. *This unintentional islanding is not permitted per IEEE 1547 (Standard for Interconnecting Distributed Resources with Electric Power Systems) and can have negative impacts from a safety and reliability perspective. All inverters utilized for photovoltaic generation are also governed by UL 1741, which requires anti-islanding protection.*

- Voltage: The majority of members on VEC's system are fed from long radial lines with small conductor; as such, distributed generation that exceeds load will typically result in a voltage rise at the point of interconnection. *To mitigate this there may be requirements for Volt/VAr compensation or system upgrades such as additional voltage regulation or reconductoring.*

- Fault Current Contributions: Protection schemes on radial feeders are designed with the assumption that current flows in a single direction and into a fault through the upstream protective devices. Distributed generators can provide fault current from alternate directions resulting in the desensitizing of existing protection. Desensitizing means that less fault current may flow through the upstream protective device than would have otherwise existed if the downstream-distributed generators were not present.

  Since faults are detected and sectionalized utilizing over-current protection schemes and an over-current relay's speed is inversely proportional to current magnitude (more current equals faster operation), the distributed generation contribution may slow the speed of operation. In some cases, it may keep the upstream protective device from reaching its pick-up current value until the distributed generators sense the fault and trip off line. In addition, given the low quantities of fault current on some parts of the system, distributed generation can further exacerbate protection margins.

  *IEEE 1547 requires all distribution generators to go off line during sustained fault conditions. Once the generation goes off-line, the upstream protective devices are no longer desensitized and should function normally. It should be noted that VEC does not foresee significant delays in its protective devices normal operation (through desensitizing) since most distribution generators contribute very little fault current to the system and go off-line very quickly during fault conditions as compared to traditional utility protection operation.*

- Voltage and Frequency Ride Through: As the penetration of behind the meter distributed generation has increased there exists increased potential for grid instability. *To mitigate these instabilities, inverters are required to ride through voltage and frequency irregularities per UL 1741-SA and ISO-NE Source Requirements document. These requirements are listed in PUC Rule 5.500*

- Transmission Ground Fault Over-Voltages: High voltages can occur during ground faults in circumstances in which a proposed generator is not effectively grounded or bonded to the system neutral and there is a relatively large generation-to-load ratio in the area. These can occur on the transmission side of the delta-wye substation transformers as well. *The least-cost solution to this problem is a direct transfer trip scheme between the transmission line breakers and distribution substation circuit reclosers, assuming fiber optic communications between the two breakers is available.*

- Substation Capacity: As large group net-metering projects that far exceed the load they serve are built, the likelihood of substation capacity constraints also increases. *While VEC does not have any locations where this has occurred, it would be up to the next project in line (developer) to pay for any substation upgrades to allow for their project to be constructed.*

- Visibility and Control: There is a concern on behalf of transmission and grid operating entities such as VELCO, ISO-NE, and the North American Electric Reliability Corporation (NERC) that in a post-blackout restoration effort intermittent distributed generation may interfere with progressive restoration of load. *VEC currently adds SCADA to provide visibility and control to all generator interconnections with a capacity of greater than 150 kW (17 solar facilities, ~4.4MW, 31.8 percent of total net-metering). That being said the remaining 1,259 locations (~9.4MW) are without any VEC visibility or control.*

  *Creating a dedicated communications pathway to add visibility and/or control to each of these locations is not financially feasible for the VEC membership. However, there are other solutions to this problem. California, a state that has a high distributed generation penetration, is working to implement coordination between California ISO (CAISO), utilities, and distributed generation developers. In this model, the distributed generation developers aggregate their resources together and have communications pathways with each of the developers. California's Rule 21 Interconnection sets out standards for communications to and from these DG aggregators.*

  *VEC has 140 different entities (around 100 of which are VEC members) that own the distributed generation. If a connection was made to the top 10 developers (by total kW), VEC would gain visibility (and potentially control) to roughly 6.5MW of generation. This information could then be shared with VELCO and subsequently ISO-NE for their benefit as well.*

  *For more information, see the Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid report put together by CAISO.*

- Transmission Constraints: The SHEI (Sheffield Highgate Export Interface) is an ISO-NE defined transmission region in northern Vermont. A VELCO-owned 115kV transmission line from Sheffield to Highgate to St. Albans and a GMP owned 34.5kV subtransmission line from VELCO East Fairfax to Lowell make up the region. Around 21,500 VEC members are fed from these transmission lines via 16 substations, and the area has significantly less load than generation.

  The average load in the region is around 35MW, and the total generating capacity is around 450 MW. This generating capacity includes imports from Hydro-Quebec on the Highgate Converter (225 MW), Kingdom Community Wind (63 MW), Sheffield Wind (40 MW), Sheldon Springs Hydro (~26 MW), Coventry Landfill (8 MW), and several other net-metering and small generation projects (~80 MW).

  Since the load in the region is often low (spring and fall) when generation from wind and hydro tend to be high, there is excess generation that needs to flow out on the transmission system. The capacity of this transmission system (originally designed to meet the load) limits its ability to export the power to the rest of Vermont and New England and as a result projects are curtailed (shut down or limited generation output).

*VEC is working with the transmission owners (GMP and VELCO) to develop the least-cost solution to this transmission constraint, which may include line upgrades or incentivized load growth. Load building within the SHEI may also provide relief to SHEI constraints, and VEC's Tier III Energy Transformation Program, discussed elsewhere in this Plan, may help with that, although we do not see sufficient load-building solutions that will allow us to "grow our way out" of the SHEI constraint.*

*VEC is recommending that any new generation over 150kW, should be located outside of the SHEI.In addition to this documentation VEC has developed a VEC-specific SHEI map and affected area for public use which is avaliable in Appendix-W and on VEC's website.*

*For further information on the constraint, please see the recent reports in Appendix-O and Appendix-P of this document, which was submitted pursuant to Act 139 in January of 2019 by the Vermont Public Service Department. In addition, VELCO discussed the potential expansion of this transmission constraint in its 2018 Long Range Transmission Plan.*

## Conclusion

Using the baseline power supply forecast, another 20 MW of distributed generation (17 MW of which will come from net-metering solar) is expected to come online by 2023.

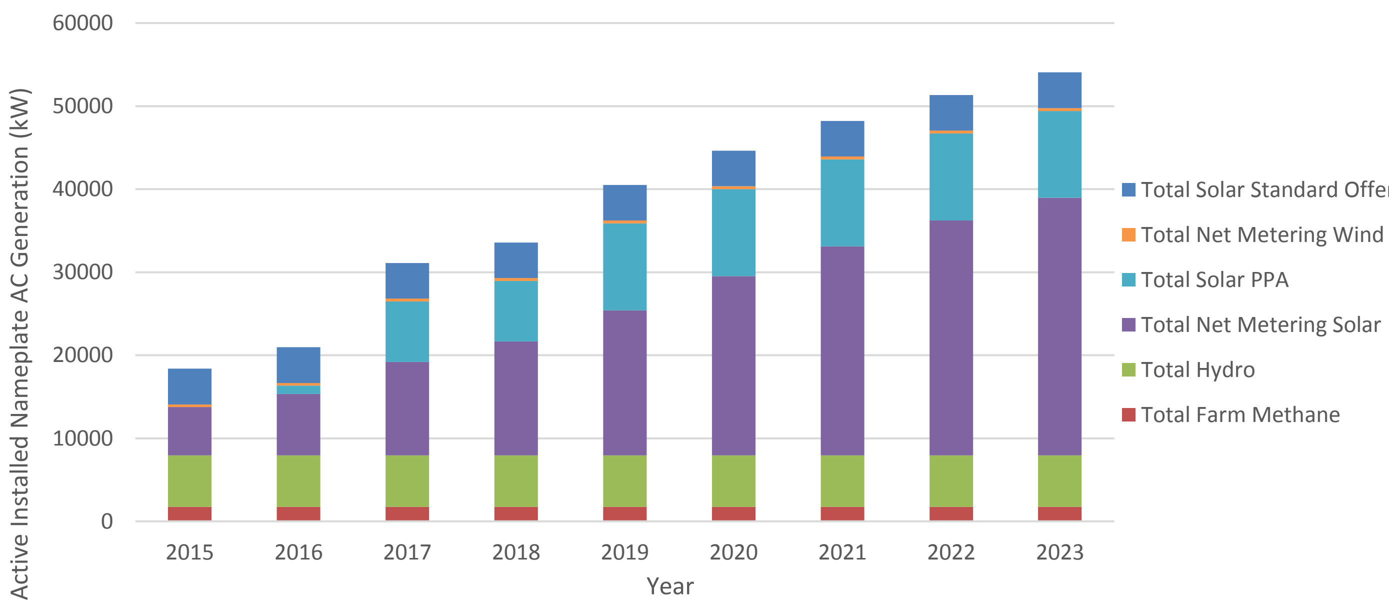



*Figure 4.6.1.E Distributed generation forecast 2015-2023*

Continued net-metering growth within VEC's service territory will need monitoring and studying. Distributed generation adds significant complexities to the power system. VEC is committed to ensuring the implementation of system upgrades and continued technological evolution to maintain reliability, safety and affordability.

### 4.6.2 Grid Impacts of Beneficial Electrification

As discussed earlier, beneficial electrification includes technologies such as electric vehicles, heat pumps, or energy storage, which allow VEC to meet its TIER III requirements and provide value through revenue and peak shaving. However, there are grid infrastructure impacts associated with these technologies, some of which can affect reliability and potentially increase costs to the membership.

As with any type of load growth, quantity and location of these technologies can have significant impacts on the electrical grid. Given the limited penetration of these technologies on VEC's distribution system today, these impacts are minimal; however as penetration increases, the likelihood of system infrastructure upgrades and member-owned upgrades related to these technologies increases.

VEC utilized the following worst-case assumptions (no load control or enhanced rate design) to determine the kW potential of each technology. In addition VEC has assigned each technology an associated diversity factor that determines the likelihood of the load occurring during the VEC system peak (1/2/18 at 6:00 PM) or substation peak (varies by substation and is typically occurs in winter or during sugaring season in March/April). These two factors are multiplied together to determine the worst-case peak kW usage per technology.

- Cold Climate Heat Pump (CCHP) – 2 kW peak kW usage (per Evaluation of Cold Climate Heat Pumps in Vermont) at a 50 percent diversity factor
- Heat Pump Water Heater (HPWH) – 1 kW peak kW usage (per Massachusetts's Energy Efficiency Council) at a 50 percent diversity factor
- Electric Vehicle (EV) – 7 kW peak kW usage at a 100 percent diversity factor[1]
- Plug-in hybrid electric vehicle (PHEV) – 5 kW peak kW usage (per Impact of EV Charger Load on Distribution Network Capactiy: A Case Study in Toronto, 2016) at a 100 percent diversity factor
- Pellet Stove – 0.3 kW peak kW usage (per Efficiency Vermont Technical Reference Manual (TRM)) at a 50 percent diversity factor
- Electric Forklift – 15 kW peak kW usage (per Electric Power Research Institute (EPRI) at a 50 percent diversity factor
- Small Clean Air Program (Small CAP) – these are typically new line extension to sugaring– 75 kW peak kW at a 100 percent diversity factor
- Large Clean Air Program (Large CAP) – these are typically new line extension or connections to sawmills and gravel pits – 500 kW peak usage at a 50 percent diversity factor

The chart below shows VEC's current and projected cumulative beneficial electrification load by year installed for the next five years utilizing the above assumptions. VEC's capital planning horizon looks out for 5 years and as such, the forecast does not include the 20-year power supply projections.

[1] Electric Vehicle Charging on Residential Distribution Systems: Impacts and Mitigations (2015); Impact of EV Charger Load on Distribution Network Capacity: A Case Study in Toronto (2016).

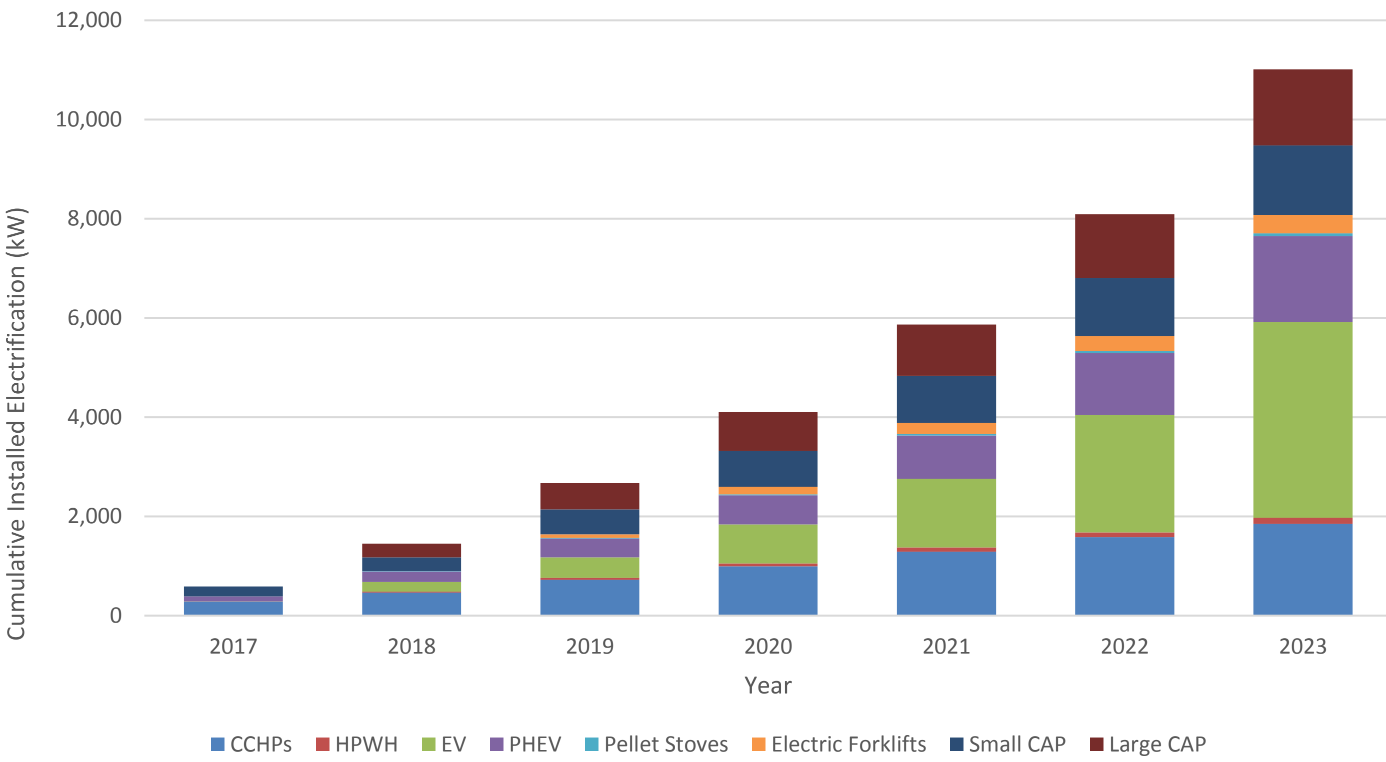



*Figure 4.6.2.A Cumulative installed electrification after diversification (kW) by year and category*

While VEC's overall load forecast is flat for the next 10 years, the forecast above focuses on energy (kWh) sales versus the demand (kW) impact of new load on the system. The electrical power system is designed to perform to certain criteria during peak demand and the additional beneficial electrification demand can cause both local and system impacts.

## System Impacts

In 2018 VEC's Tier III program added new electrification of approximately 1.4 MW (35% CCHP or HPWH, 29% EV's or PHEV's, and 40% CAP). The total forecasted Tier III increase is around 11 MW by 2023, which is about 13 percent of VEC's system peak (approximately 85 MW). VEC receives very limited advanced notification for these types of loads making it critical to perform annual system planning and identify alternatives to notification.

As part of VEC's 2018 System Load and Voltage Study, VEC applied a five percent increase to the load on the system to identify any overloaded assets or violations of loading and voltage criteria. VEC identified several constrained areas in this study including some areas that exceeded VEC's criteria even without the five percent increase.

The new beneficial electrification load detailed above is much higher than the five percent and as a result, VEC conducted a new study in 2019 to identify constrained areas. VEC used two methodologies: equal allocation of load growth and distributed allocation of load growth, as explained below.

**Equal Allocation of Load Growth**

VEC applied a flat 13% increase to all substation peaks and then allocated this load amongst the member load based on existing usage via VEC's Milsoft Engineering Model. This analysis identified constraints at the system level; any location-based constraints (distribution transformer capacity and service voltage quality) are discussed in further detail below.

VEC found 17 system constraints when performing this analysis, each of which were grouped into the following categories:

- Substation capacity – load growth causes need to upgrade or plan to upgrade a substation transformer due to the load exceeding 80% of the transformer's capacity.
- Voltage outside of tolerance – load growth causes low voltage on weak sections of the distribution circuit. These weak sections are generally a function of line distance, quantity of phases, voltage rating (2400V versus 7200V), and type/size of conductor. Additional voltage regulation, reconductoring, or voltage conversions may be required.
- System protection upgrades – load growth causes the need to upgrade reclosers and fuses to ensure proper sectionalizing of the distribution system.

VEC plans to prioritize these upgrades in the capital plan based on annual load growth reviews. A map of the constraints identified in the equal allocation of load is available in Appendix-Q of this document

**Distributed Allocation of Load Growth**

The distributed allocation has three components:

1. For non-CAP loads (EV, PHEV, HPWH, CCHP, Pellet Stoves, and Electric Forklifts), VEC assumed that increases in load would be located based on the distribution of existing net metering. This is in line with VEC's existing load growth for non-CAP loads. VEC utilized its existing net-metering database to identify the percentage of net-metering on each substation as compared to the total net-metering on the system. This percentage was multiplied by the total kW increase of non-CAP load to identify a kW increase on each substation.
2. For Small CAP loads (sugaring operations), VEC assumed that increases in load would be located based on the distribution of existing sugaring loads throughout VEC's territory. To accomplish this VEC utilized its existing database of sugaring load to identify the percentage of sugaring kVA capacity on each substation as compared to the total sugaring kVA on the system. VEC multiplied this percentage by the total kW increase of Small CAP load to identify a kW increase on each substation.
3. For Large CAP loads (sawmills and gravel pits), VEC assumed that increases in load would be located based on the distribution of existing commercial loads throughout VEC's territory. To accomplish this VEC utilized its existing database of commercial load to identify the percentage of commercial kVA capacity on each substation as compared to the total commercial kVA on the system. VEC multiplied this percentage by the total kW increase of Large CAP load to identify a kW increase on each substation.

Each of the kW increases from sections 1, 2, and 3 were added together and divided by the 2018 substation peak load to determine a percentage increase, which was then used in the Milsoft model for each location. The chart below shows the kW increases by type, total kW increase, percentage increase, and whether or not the load would occur in the SHEI.

| VEC Substation | Increase EVs/Heat Pumps (kW) | Increase Small CAP (kW) | Increase Large CAP (kW) | Total Increase (kW) | 2018 Peak (kW) | Percentage Increase | SHEI? |
|---|---|---|---|---|---|---|---|
| Fairfax 01 | 543 | 187 | 6 | 735 | 3,137 | 23.4% | No |
| Eden 02 | 129 | 101 | 8 | 238 | 1,814 | 13.1% | No |
| Cambridge 03 | 169 | 76 | 9 | 254 | 1,666 | 15.3% | No |
| Underhill 04 | 384 | 41 | 2 | 427 | 1,145 | 37.3% | No |
| Lowell 05 | 149 | 62 | 10 | 220 | 1,300 | 17.0% | Yes |
| St. Rocks 06 | 229 | 99 | 8 | 335 | 1,696 | 19.8% | No |
| Montgomery 07 | 76 | 38 | 4 | 118 | 954 | 12.3% | No |
| Richmond 08 | 376 | - | 7 | 384 | 1,150 | 33.4% | No |
| Williston 09 | 490 | 3 | 99 | 593 | 2,947 | 20.1% | No |
| Jericho 10 | 297 | 2 | 15 | 314 | 1,035 | 30.3% | No |
| Westford 11 | 208 | 9 | 6 | 222 | 864 | 25.7% | No |
| Fairfax 12 | 183 | 55 | 2 | 240 | 1,230 | 19.5% | No |
| Pleasant Valley 13 | 275 | 70 | 9 | 353 | 1,167 | 30.2% | No |
| Johnson 14 | 167 | 15 | 6 | 188 | 1,287 | 14.6% | No |
| Madonna 15 | 48 | 26 | 114 | 188 | 6,054 | 3.1% | No |
| Jay 17 | 18 | 28 | 19 | 65 | 997 | 6.6% | Yes |
| Hinesburg 19 | 1,091 | 26 | 22 | 1,139 | 5,799 | 19.6% | No |
| French Hill 20 | 17 | 22 | 0 | 39 | 274 | 14.4% | No |
| Highgate Springs 27 | 28 | - | 6 | 35 | 858 | 4.0% | No |
| South Alburgh 28 | 362 | 6 | 48 | 416 | 6,740 | 6.2% | Yes |
| South Hero 29 | 1,106 | 1 | 68 | 1,175 | 6,721 | 17.5% | No |
| East Berkshire 30 | 317 | 118 | 37 | 472 | 3,332 | 14.2% | Yes |
| Richford 31 | 82 | 85 | 51 | 217 | 4,000 | 5.4% | Yes |
| Sheldon 32 | 212 | 44 | 20 | 276 | 2,734 | 10.1% | Yes |
| Jay Peak 40 | - | - | 24 | 24 | 5,923 | 0.4% | Yes |
| North Troy 41 | 120 | 8 | 36 | 164 | 2,756 | 6.0% | Yes |
| Irasburg 42 | 158 | 46 | 35 | 238 | 3,580 | 6.7% | Yes |
| Burton Hill 43 | 210 | 48 | 15 | 274 | 2,773 | 9.9% | Yes |
| Newport 44 | 139 | 1 | 263 | 403 | 9,088 | 4.4% | Yes |
| Derby 45 | 167 | 14 | 119 | 301 | 6,230 | 4.8% | Yes |
| Island Pond 46 | 40 | 107 | 9 | 156 | 1,974 | 7.9% | Yes |
| Island Pond 47 | 15 | 17 | 24 | 56 | 1,744 | 3.2% | Yes |
| West Charleston 48 | 220 | 30 | 22 | 272 | 2,637 | 10.3% | Yes |
| Norton 50 | 10 | 11 | 4 | 25 | 408 | 6.1% | Yes |
| Canaan 51 | 46 | 5 | 18 | 70 | 3,082 | 2.3% | Yes |

*Table 4.6.2.A Expected kW increase by substation and location in SHEI*

Based on the distributed allocation, only 3.6MW of the total 11MW would occur in the SHEI. VEC is investigating opportunities (bill credits, CAP projects, etc.) that will hopefully change this allocation to grow more load in the SHEI and hopefully reduce the existing curtailments that occur.

This analysis identified constraints at the system level; any location-based constraints (distribution transformer capacity and service voltage quality) are discussed in further detail below. VEC found 22 system constraints when performing this analysis, each of which were grouped into similar categories mentioned in the equal allocation of load above.

VEC will prioritize these upgrades in the capital plan based on annual load growth reviews, as was the case with the equal allocation of load. A map of the constraints identified in the distributed allocation of load is also available in Appendix-R of this document

## Locational Impacts

**Electric Vehicles**

VEC expects around 52 percent (5.6MW) of this new load to occur because of electric vehicles (EV and PHEV) between 2019 and 2023. There have been several studies completed by IEEE and other journals that analyze the grid impacts of EV charging load.[2] In each study, potential risks are identified related to service transformer overload and service voltage drop. These risks and associated utility infrastructure costs can be mitigated if proper utility planning and notifications occur prior to the purchase and installation of EV charging equipment.

Some studies conclude that 20 percent is a reasonable level of EV penetration that results in no overloading of existing distribution networks.  However, other systems can tolerate only 10% of uncoordinated charging load that could be raised to 40% in the case of charging coordination.  In reality, it appears that every distribution network is a special case, requiring an independent study to explore the issues and limits of EV charging load.

As to EVs driving the need for transformer upgrades, the average residential member will draw around 3 kVA and in some cases up to 8 kVA. A 10 kVA transformer is generally used for residential loads, and this size transformer would allow for additional members to be added. In more developed areas where multiple members may be fed off the same transformer, an electric vehicle purchase may cause the need for a transformer upgrade to ensure system reliability and performance.

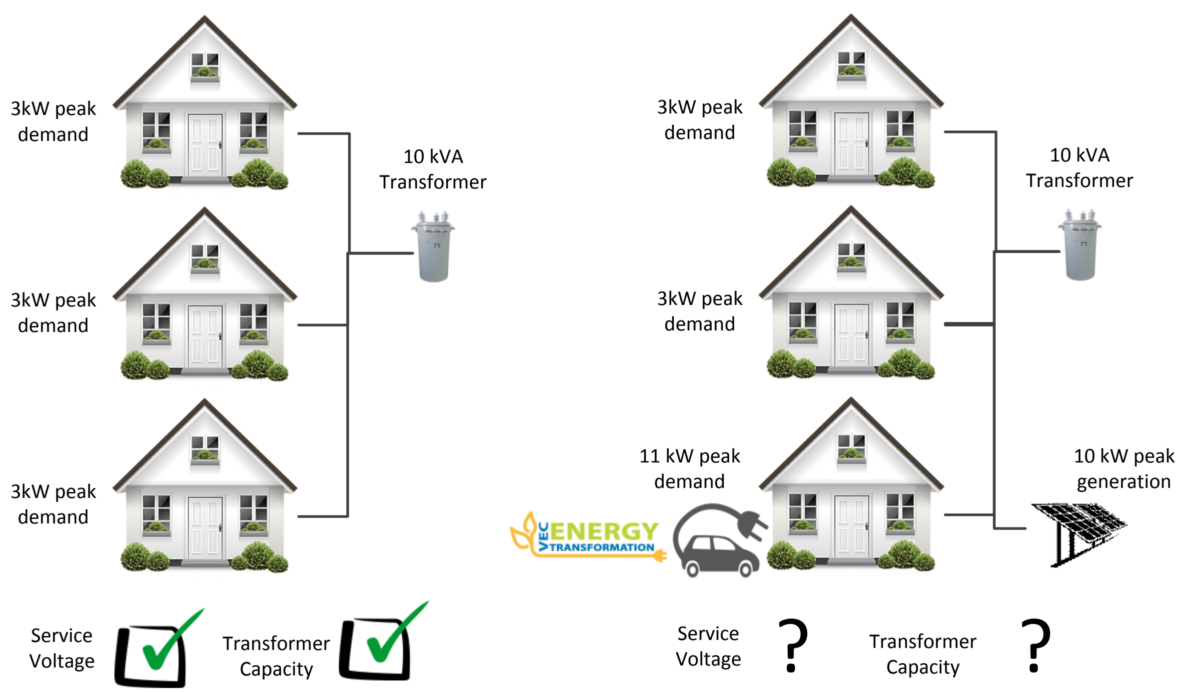



*Figure 4.6.2.B    Service voltage and transformer capacity review process*

[2] Electric Vehicle Charging on Residential Distribution Systems:  Impacts and Mitigations (2015); Impact of EV Charger Load on Distribution Network Capacity:  A Case Study in Toronto (2016).

Most EV charging occurs at home and can add significant load to an electric service and premises electrical wiring and circuits. Voltage drop could be a concern depending on distance of EV charging stations from the utility's service transformer. Proper member planning with members' electricians can mitigate these risks.

**Heating**

Heat pumps and pellet stoves follow along the same lines as the EV charging discussion above; however, these resources may be used for longer periods throughout the day and night as compared to EV charging and may also result in additional incremental load if all three resources are used at the same time. The utility and members' electricians should be notified of these additions before purchasing of this equipment in order to plan for any necessary utility or member-owned electrical upgrades.

**Clean Air Program (CAP)**

VEC's Clean Air Program (CAP), which was initiated in 2016, offers customized opportunities to members with off-grid or underserved homes or businesses to replace fossil fuel usage with electricity. These opportunities may include service upgrades or line extensions, with the costs shared between the utility and the member through customized agreements.

Under the CAP program, VEC helps members pay for line extensions or service upgrades (typically a 20-25 percent contribution) in order to eliminate fossil fuel generators, allowing the members to use VEC's 73 percent carbon free and 58 percent renewable power portfolio to displace a fossil fuel source. This program is a great example of the win-win-win where the member typically receives a reduction in their line extension costs and savings in their annual energy costs, VEC increases its sales of clean electricity, and the general public benefits from reducing carbon dioxide from fossil fuel based generators (typically propane, diesel fuel, or gasoline). This program is also in direct alignment with the State of Vermont's clean energy initiatives and helps VEC meet its Tier III requirement.

VEC has had eight successful projects since the program began in 2016, adding approximately 500 kW of load between 2017 and 2018.

Each CAP project requires fuel receipts (in the case of an existing generator) to estimate the additional electric load and resulting carbon savings. In the case of a project that currently does not have a generator (for example a new sugaring operation which is considering a fossil fuel generator), we estimate what the consumption and corresponding carbon use would have been based on the projected power requirements of the operation. Once the projected load is determined, VEC reviews each project for system upgrades, analysis of load profile, increases electric sales, and net present value (NPV) payback period.

## Conclusions

The electrical power system is designed to perform to certain criteria during peak load. While the additional load proposed presents challenges, VEC is confident that with effective load control and rate design, the constraints identified above will not need to be mitigated with costly grid upgrades. VEC plans to do an annual analysis, using equal and distributed allocation, of the existing and forecasted load to ensure the safe operation and reliability of the grid.

## 4.6.3 Energy Storage

VEC has approximately 270 kWh and 100 kW of residential battery systems installed on its system as of the end of 2018, and we expect to see further growth in the coming years as technological advances occur and prices drop.

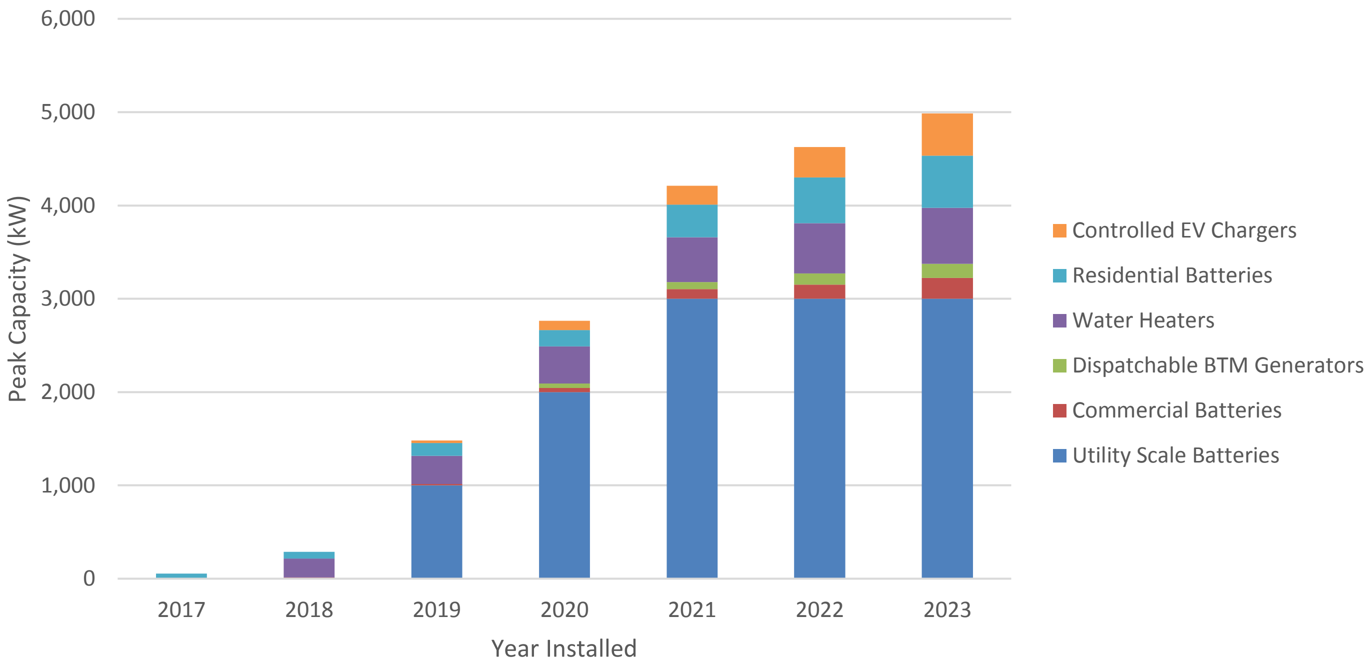



*Figure 4.6.3.A Cumulative installed and forecasted storage (kW) 2017-2023*

Residential storage systems (residential batteries, EV chargers, water heaters, and dispatchable generators) can act as load or as a load reducer. VEC reviews each new application for storage to ensure that the member's service can handle the potential new load without the need for a service upgrade. VEC also assesses these systems for distribution grid impacts that could be caused by the increase in load.

Utility scale storage can affect the grid in a number of different ways. Each utility scale project generally includes a System Impact Study (SIS), which analyzes load flow, thermal loading, reverse power flow, voltage, and other protections. The SIS will also review charge and discharge rates, both of which can vary greatly depending on the size and specific operating requirements of the project.

The SIS for the planned 1.9 MVA battery energy storage project located adjacent to the VEC Hinesburg #19 substation identified the need for settings changes and replacement of several reclosers and regulators. In addition, VEC identified that a potential substation upgrade may be required in the future if the project causes the peak load to exceed 80 percent of the substation transformer nameplate rating, therefore exceeding VEC's design criteria.

## 4.6.4 Data

VEC has several key data sources and analytical tools critical to the day-to-day functions of the cooperative that allow for understanding of the complex power system, VEC members and their usage, and enhancements to utility operations. Data and data analysis are increasingly important as the grid becomes more complex through the addition of distributed generation, battery storage and other load control devices. These data sources that are listed in further detail below:

## AMI (Automated Metering Infrastructure)

VEC has been operating its present Aclara based AMI system since 2005. The system relies on powerline carrier (PLC) signals communication to provide two-way communications between the VEC substations and meters. Data backhaul from the substation is currently provided using a mix of fiber optic cable, private carrier Ethernet, or cellular. VEC utilizes this system for 99% of demand usage metering and outage monitoring on residential, small commercial and industrial consumers.

VEC uses the National Information Solutions Cooperative (NISC) "iVUE" system to house meter data in its Meter Data Management (MDM) system. In addition, we use iVUE for billing and for VEC's consumer interface application, SmartHub. SmartHub is a mobile and web-based application that allows members and VEC to view usage information and set alerts. This tool empowers VEC members to make changes that help them reduce their energy usage and ultimately lower their energy bill. SmartHub also provides members with a method of notifying VEC of an outage or receiving notifications from VEC.

While the cost of a residential 2S AMI meter is higher than a non-AMI meter ($40 versus $20) the benefits of fewer manual meter reads (and associated management and administrative support), increased meter reading accuracy, and outage management significantly outweigh the costs. VEC is currently able to purchase AMI meters at lower than manufacturer costs due to surplus units that have been fitted with AMI modules. However, VEC expects this supply to run out, and comparable units at full price range from $100-$160.

VEC replaces meters on a 10-year cycle or as failures occur. The advertised life expectancy is 15 years and is based on one read per day. VEC currently does three reads per day or once every 8 hours. Therefore, there is a lower life expectancy on its meters. The AMI meter communication involves a high-current pulse generated by the meter, which puts a level of stress on the AMI meters, hence shortening their life span/expectancy.

VEC is in the process of upgrading from its existing Aclara TWACS power line carrier system to a newer version called eTWACS (enhanced TWACS). eTWACS is a system that is made up of various components from the office to the substation to the service point. It utilizes a new software platform that offers improved performance and enhanced features. These enhancements include:

- Utilization of Aclara's Fault Detection and location software to automatically detect an outage in less than 190 seconds. VEC's current Outage Management System (OMS) requires a phone call to initiate an outage query whereas the new system will be capable of actively polling meters to determine outage status.
- Identification of momentary outage counts (also referred to as "blinks") for each meter, a data point that is not identifiable with present system and is becoming increasingly important as more members work from home.
- 15-minute interval voltage and reactive and real power data to support system planning and develop projects to reduce outage times and system losses.

In 2018, VEC began upgrading the system and future plans are discussed further in Section 5 - Action Plan.

## Supervisory Control and Data Acquisition

Supervisory Control and Data Acquisition (SCADA) enables VEC to view real time data as to the status of equipment and other assets (open vs. closed for instance) as well as their analog values (power, voltage, current, etc.). It also allows us to remotely operate assets such as reclosers and switches.

In 2011, VEC received a $5.7 million dollar grant from the Department of Energy that facilitated the modernization and upgrade of almost all VEC substation reclosers and regulators and implementation of SCADA to over 65 locations including at all VEC substations and metering points (roughly 11,000 data points). VEC supplies much of this information to VELCO for operational and planning purposes via an Inter-Control Center Communications Protocol (ICCP) connection. These investments took place over four years and VEC was able to complete almost $11.4 million worth of projects with a 50 percent cost share with the Department of Energy.

Remote or supervisory operation allows VEC to save labor hours and reduce outage times by allowing remote switching and tagging, reducing or eliminating travel time to the field or between devices. Travel and labor hours can be reduced by eliminating trips to the field for to place monitoring devices, to perform switching and tagging for maintenance and outage restoration activities and to perform operational mandates such as voltage reductions tests or events. The overall result is shorter outages and lower costs.

Real-time monitoring (2-second intervals) provides visibility for system operations to monitor and react to events on the power system. In addition, as VEC sees more multi-direction electric flows throughout its system, the real time data provides engineering and planning with a view into the system that can be used to review system irregularities (such as voltage drops or outages) and planning analysis (identification of substation transformer upgrades or load balancing). While this data is a great asset, one of the challenges VEC faces is data validation and accuracy. The devices and relays that provide data to the Remote Terminal Units (RTUs) are not revenue grade and generally have an accuracy rate between 3-5%. This level of accuracy is adequate for high level planning but VEC continues to rely on revenue grade Electro Industries Nexus meters at its substations, some of which are connected to SCADA and others that can be accessed by cell modem, or Power Quality (PQ) recorders to review system events. There are 60 Nexus meters that provide data from substations, tie points, and several large customers. Not all VEC substations and metering points are equipped with this technology but VEC intends to continue deploying real time capable, high accuracy meters, across its system.

In addition, VEC utilizes an OSIsoft PI Historian, which archives SCADA data for use in post-mortem review of system events and anomalies as well as for system planning. VEC has built dashboards to enable mobile access to SCADA data for use by field personnel, which provides near real time visuals of the system during SCADA commissioning and during equipment maintenance.

## Geographic Information System (GIS)

VEC's utilizes its Geographic Information System (GIS) to store GPS coordinates and attributes of system assets. The system runs on an ArcGIS server, which is an Environmental Systems Research Institute (ESRI) product. The GIS sits at the center of our Customer Information System (CIS), and Accounting Business Solution (ABS) and is integrated with VEC's engineering model.

GIS map editing allows new services, line relocations and other changes to the VEC system to be added to the GIS as part of the normal workflow of VEC's engineering and design staff. In this way, all portions of the VEC electric system can be displayed in a series of mapping tools. The electric connectivity of the GIS is used to integrate with VEC's Outage Management System (OMS), also created by NISC. The GIS system is integrated with Clearion Vegetation Management software use to schedule and track the clearing of VEC rights-of-way.

VEC distributes shape files of the electric system to the Vermont Open Geodata Portal via VCGI (Vermont Center for Geographic Information). These shape files include pole locations, wire (overhead and underground), and number of phases. While this information is limited, VEC regularly distributes more detailed GIS data to a number of utilities, state entities, and supporting vendors for uses such as system planning or utility location services to support the DigSafe program.

During an information gathering initiative in 2000, VEC was able to capture GPS coordinates. As the system has become more interconnected with other areas of the company, the mapping system has evolved into an asset management tool, increasing the importance of accurate asset data (pole heights, pole attachments, transformer sizes, fuse sizes, etc.). To ensure data integrity, VEC is engaged in a five-year assessment and inspection of its system (distribution transmission and substation) to gather key asset attribute data. Please see the Maintenance section for more detail on this plan.

In addition, VEC has many more initiatives focused on continuing to enhance GIS and expand its offerings as it becomes more foundational to everything VEC does.

### 4.6.5 Cyber-Security

VEC believes a strong cyber-security culture is essential to our future to ensure the reliability of the electric grid. The most significant risk is human behavior. Social engineered attacks, i.e., those designed to exploit the weaknesses of people rather than systems, are the most common and dangerous. Furthermore, with the increased use of technologies such as SCADA and AMI, VEC's various business and operations systems have become better able to communicate with each other. These integrated, autonomous and complex systems have accelerated evolution of more sophisticated threats and attacks. The North American Electric Reliability Corporation (NERC) has identified the greatest cyber-security risks facing the North American electric grid today (in order):

- Human error
- Access control management
- Insider access
- Insufficient training
- Lack of vigilance by all stakeholders

VEC recognizes and meets these evolutions with a commensurate level of cyber-security. VEC utilizes a layered, "Defense in Depth" approach to cyber security to safeguard member information and business systems. Defense in Depth is an approach to cybersecurity, layering a series of defensive mechanisms to protect valuable data and information. If one mechanism fails, another steps up immediately to thwart an attack. Additionally, VEC follows the Department of Energy Electric Sector Cyber Capability Maturity Model (DOE ES-C2M2) to evaluate, prioritize, and improve cybersecurity capabilities. Using the ES-C2M2 framework, VEC has increased its cyber capabilities to address a wide-ranging array of both technical and socially engineered attacks. Each year VEC looks to improve one Maturity Indicator Level (MIL) in at least two domains as outlined by the C2M2 model.

Internally, VEC maintains its Information Technology-IT (e.g., regular corporate network, computers, firewalls, etc.) and Operations Technology-OT (e.g., SCADA, Control Center connectivity, firewalls, etc.) in separate domains with each domain treating the other as if it is an outside entity. Each domain has procedures in place for isolating from each other and islanding from any external or public connections. Where possible and appropriate, each group uses different sources and equipment for the various functions of cybersecurity including network devices, network segmentation, network isolation, intrusion detection, endpoint protection, and system event and information monitoring. This model includes continual improvement on bother systems (e.g., upgrades, updates, patches) and personnel (e.g., training).

Additionally, VEC trains, tests, and develops its employees in the areas of cyber-security awareness and good cyber-hygiene. VEC's cyber-security team conducts training for, and testing on, all VEC employees bi-annually. Employees discuss cyber-security awareness topics as part of a "Safety/Cyber Minute" before the start of most meetings. Additionally, VEC's cyber-security team provides an in-depth review of threats weekly for members of Engineering and Operations, especially field personnel. E&O shares this information with the entire company via the corporate internet.

Externally, VEC collaborates with partners and professionals such as the Department of Homeland Security (DHS) and the National Guard to develop and exercise its cyber-security skills to identify areas for improvement. VEC participates in cyber-exercises annually with the DHS and National Guard (Vigilant Guard, Cyber Yankee). VEC monitors and participates in the following forums to identify and share emerging threats and best practices:

- Multi-Sector Information Sharing and Analysis Center (MS-ISAC)
- Electrical Sector Information Sharing and Analysis Center (E-ISAC)
- United State Computer Emergency Readiness Team (US-CERT )
- Industrial Control Systems Emergency Readiness Team (ICS-CERT)
- SANS Institute and Internet Storm Center
- VT Fusion Center

### 4.6.6 Transformer Load Management

Transformer load management involves the review and analysis of transformer utilization for both low and high use scenarios. This involves comparing the combined member demand with the transformer rating (kVA).

Almost half of VEC's system has inaccurate or missing transformer size information, therefore making any sort of analysis difficult or inconclusive. As part of VEC's Maintenance Plan initiative, VEC will verify and acquire information needed to perform accurate load management and analysis. Added features and communications capabilities provided by the planned AMI system upgrade will also support effective transformer load management. VEC also intends to purchase a transformer load management software in 2019 to allow analysis of the areas where accurate information exists. The software will allow VEC to:

- Detect over and under loaded transformers.
- Calculate coincident demand.
- Calculate the energy supplied.

## 4.7 Operational Excellence

### 4.7.1 Outage Management

As noted elsewhere in this plan, 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" AMI meters upstream 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.

VEC strives to provide its members with the most up to date and user friendly outage information. VEC has recently made several improvements to its public outage page including a more modern map that provides better graphical representation of outages, better detail and location of outages (e.g., service territory, town/county boundaries, roads and other landmarks, use of circles to indicate size of outage, etc.), and modifications to outage tables. In addition, we also use the OMS to manage outage response and provide updated ETRs to members. Members can sign up for text or email alerts depending on their preferences.

VEC began upgrading is AMI system in 2018, as noted above, with the goal of automatically detecting an outage in less than 190 seconds, actively polling meters to determine outage status, identification of momentary outage counts (also referred to as "blinks") for each meter, and 15-minute interval voltage and reactive and real power data. All of which, should greatly enhance VEC's outage response capabilities and services.

### 4.7.2 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 (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-I 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 of 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 as well as 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. VEC will also determine external crew requirements.

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 or the National Guard. VEC also offers Mutual Aid assistance to the following categories of utilities:

- 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.

External crews are led by VEC qualified personnel, provided VEC-specified material and GIS mapping tools.

Finally, VEC may offer assistance to utilities outside of Vermont if internal resources permit. For more information, see OP-57 in Appendix-H.

### 4.7.3 Weather and Climate

Weather (short-term changes around 24 hours) and climate (long-term changes around 30 years) have both significant impacts to VEC's event response, outage management, and capital 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 (e.g., Northview Weather in Lyndonville, VT) to understand the challenges and potential solutions associated with weather and climate and to enhance our operational response.

#### Partnership with Vermont Weather Analytics Center

VEC is an active participant in the Vermont Weather Analytics Center (VWAC) that began in 2014 as a research and development project between VELCO and IBM Research. Through a Joint Development Agreement among VELCO, Vermont utilities, the State of Vermont, higher education institutions (the University of Vermont, Norwich University and Northern Vermont University - Lyndon), and other stakeholders, the R&D effort has provided extensive value for grid management. It has also identified needs the project could address beyond the electric system in areas such as road safety, ski area maintenance and agriculture. In 2016, the initial Joint Development Agreement was extended for a third year.

#### 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 VWAC and 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.

The table below, provided by Northern Vermont University-Lyndon through support of VLITE, shows several weather parameters (temperature, precipitation, and wind) and the percentage improvement resulting from weather station installations.

| Parameter | Distance from reporting site | Percent of Vermont Covered (2017) | Improvement over 2016 (%) |
|---|---|---|---|
| **Temperature** | > 5mi | 33.4% | 6.9% |
| **Temperature** | > 10mi | 5.0% | 4.0% |
| **Precipitation** | > 5mi | 44.0% | 11.1% |
| **Precipitation** | > 10mi | 2.8% | 15.1% |
| **Wind** | > 5mi | 36.7% | 8.7% |
| **Wind** | > 10mi | 0.6% | 5.1% |

*Table 4.7.3.A Weather parameters and the percentage improvement resulting from weather station installations*

The installations completed by VWAC, VEC, and other entities had improved weather forecasting capabilities by increasing the percent of Vermont that is within 10 miles of a reporting site Further improvement could be accomplished with additional weather station installs; however there are more cost effective solutions. One of these solutions is to use more citizen-science observers (https://www.cocorahs.org/) across the region to help with daily precipitation (wet snow and ice) observations.

Such observations help validate and update existing weather forecasts and models and in turn yield better forecasts. In addition, observations help VEC develop a better understanding of weather risks as they relate to outage risks, especially if we can sample conditions post-event.

## Partnership with Northern Vermont University – Lyndon and Northview Weather

**Forecasting Tools**

A collaboration between Northern Vermont University - Lyndon and a recent startup organization, Northview Weather, has focused on enhanced approaches to utility forecasting. In particular, they are studying the utility impacts of wet snow, ice, and wind, with the goal of reducing outage restoration costs. Northview Weather is developing 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 will allow utility management to plan for the appropriate personnel and to deploy those personnel to targeted locations, in some cases prior to the event. In addition, Northview Weather 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.

**Climate and Weather Research**

In addition to the forecasting tools above, VEC and the distribution utilities are working with Northern Vermont University – Lyndon 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.

The research will be broken up into two components:

- What has happened in the past?

    - Examine changes in weather-driven outages with participating DUs.
    - Work with participating DUs to better understand non-weather factors influencing outage variability.
- What may happen in the future?
    - Examine the frequency and magnitude of weather hazards changing in different climate change scenarios.
    - Examine future weather risks as they translate to grid assets to highlight the greatest areas and types of future outage risk.

The outcome of this research project would be a comprehensive public report discussing current and future weather risks to the grid in Vermont and associated utility impacts. This information will help VEC and other participating utilities better understand the impacts of weather on our grid, modify our philosophies and standards, and find cost-effective solutions to maintain reliability for our members.

## 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 of these grant opportunities. FEMA designs these grants to cover costs for restoration and mitigation projects that make the system affected by an event and 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. While the additional funding is valuable, it does require resources and time to build the grants and monitor them but VEC finds this effort worthwhile.

**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 project 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 prevent mitigate future outages.

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.

**Section 406 – Public Assistance**

In addition to Section 404, VEC plans to investigate applying for Section 406 – Public Assistance in 2019. FEMA does not tie these funds to a particular 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 an additional investment in VEC's distribution system for improvement and reliability.

VEC prioritizes all capital projects utilizing its [Capital Project Prioritization Process](). 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.

### 4.7.4 Maintenance

As part of a concerted effort to maintain and document all T&D assets, VEC implemented a comprehensive maintenance program on January 1, 2019. The program is broken up into two major components:

- A five-year "System Assessment" with the goal of gathering of accurate asset data such as conductor and transformer sizes, manufacturers, serial numbers, proper phasing. The data will be populated in VEC's GIS system via NISC's AppSuite Inspections software utilizing both internal VEC personnel as well as contractors.
- An ongoing, scheduled, system-wide maintenance plan that addresses all hardware and major equipment allowing VEC to evolve from a run-to-fail methodology to proactive maintenance.

VEC will update this plan annually during the third quarter of the year to identify which circuits it will review and to document any changes to the plan. The objectives of VEC's T&D maintenance program include:

- Maintain VEC's electric transmission, substation, distribution, and metering system on a comprehensive schedule and scale that allows for work prioritization and changing requirements while complying with:
    - Rural Utility Service (RUS) requirements/recommendations
    - National Electric Safety Code (NESC) requirements
    - ISO-NE Regional Reliability Standards
    - Institute of Electrical and Electronics Engineers (IEEE) standards
    - American National Standards Institute (ANSI)
    - Manufacturers' recommendations
    - VEC standards and operating policies
- Enhance reliability and proactively reduce preventable outages for VEC's members as measured annually by duration (SAIDI), frequency (SAIFI), and customer average (CAIDI) outage minutes, as well as system-wide root cause analysis findings to drive maintenance of VEC's worst performing circuits.
- Extend plant life of VEC's capital assets and thereby reduce upward pressure on member rates.
- Deliver accurate system data to various departments within VEC and ensure the highest level of data integrity.
- Provide a documented electric transmission, substation, and distribution maintenance policy that clearly defines VEC's system operations core business, expectations for employees, and specific maintenance work functions. In addition, this program provides the information that ensures consistency to system operations personnel in the inspection, testing, and maintenance of VEC's electric system plant, equipment, and other facilities.
- Capture asset and maintenance information by leveraging technology. This includes using NISC's AppSuite Inspections software so information can be populated directly into GIS. It also includes further integration between GIS, NISC's CIS (Customer Information System), and VEC's Milsoft WindMil model.

For more information, see Appendix-L.

### 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" 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 set and maintenance areas. VEC inspects all of its sole owned distribution poles across the system as well as 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.

VEC replaces any rejected poles within twelve months of the pole inspection.

## 4.7.5 VEC System Operations

In addition to great technology, VEC is fortunate to have highly trained system operators who manage and respond to the power system. System Operations monitors the power system via SCADA and OMS and provides support to field personnel as required. Qualified system operators staff VEC's control room twenty-four hours a day, seven days a week. In addition to utilizing SCADA and OMS, system operators also utilize a security system which provides real time video footage of all of VEC's service facilities (Grand Isle, Richford, Newport, and Johnson headquarters), and over ten substations within VEC's system.

*Figure 4.7.5.A VEC control room*

VEC has a backup control room and computer server room in an undisclosed location close to VEC's telecommunications network and in an area that would not be affected by localized natural disasters (tornados, flooding, etc.) that could affect VEC's primary control room in Johnson.

The backup control room/server room houses the SCADA System B Server as well as an operating system that is identical to VEC's primary system. Operators can access operating documents through the VEC Intranet system that is also backed up at this location. VEC also maintains paper copies of all operating documents at this location.

All other systems including OMS, mapping, radio and other company network services are available at the backup control room. There are phone restrictions due to infrastructure limitations so in the event VEC needs to operate from the backup control room, VEC would rely heavily on an external call-center support provider to handle at least a portion of member calls.

VEC Operating Procedure OP-30 -- Evacuation of Control Room, which VEC tests annually, guides all company actions in the event that this is required.

### 4.7.6 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 to ensure that any company-initiated outages create the least possible inconvenience. VEC Operating Procedure OP-59 identifies those interested in receiving outage information, defines outage notification criteria and identifies the communication methods.

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 4.7.6.A 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-J.

## 4.8 Reliability

It is our mission and core responsibility that VEC builds, maintains, and operates the most reliable power system at the least cost to our members. VEC spends significant time and resources preventing and responding to outages and working to share outage information transparently with our members and regulators.

This section contains VEC's outage mitigation philosophies and a detailed assessment of VEC's outage performance from 2014 to 2018. VEC has identified specific future actions or projects in Section 5 - Action Plan.

### 4.8.1 Philosophies

The following section describes VEC's philosophies on outage mitigation and response through strategies such as vegetation management, system protection, and/or feeder backup.

#### Vegetation Management

VEC has a responsibility to maintain vegetation on its system in order to preserve the safety and integrity of our overhead electric facilities. Since 60-70 percent of VEC's distribution line 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 in order 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 maintain a healthy and beautiful Vermont.

Specifically, the VEC Vegetation Management Department is responsible for maintaining vegetation in order to minimize the threat it poses to electric facilities. The vegetation management program takes an environmentally responsible approach to meet the following goals:

- Improve reliability
- Provide for safe and efficient operation and maintenance of distribution and transmission systems
- Enhance member satisfaction
- Maximize cost-effectiveness

Establishing and maintain the correct vegetation maintenance cycle is critical to meetings these goals.

In 2009, VEC filed a vegetation management plan that addressed funding, maintenance cycles, and performance. 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.

Since then, VEC has executed its plan with a commitment to meet annual mile targets while remaining flexible to address immediate safety and reliability concerns (e.g., hot spotting) and member concerns. The plan has proven to be effective, with VEC achieving a five-year cycle for transmission ROWs and reaching the tenth year 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.

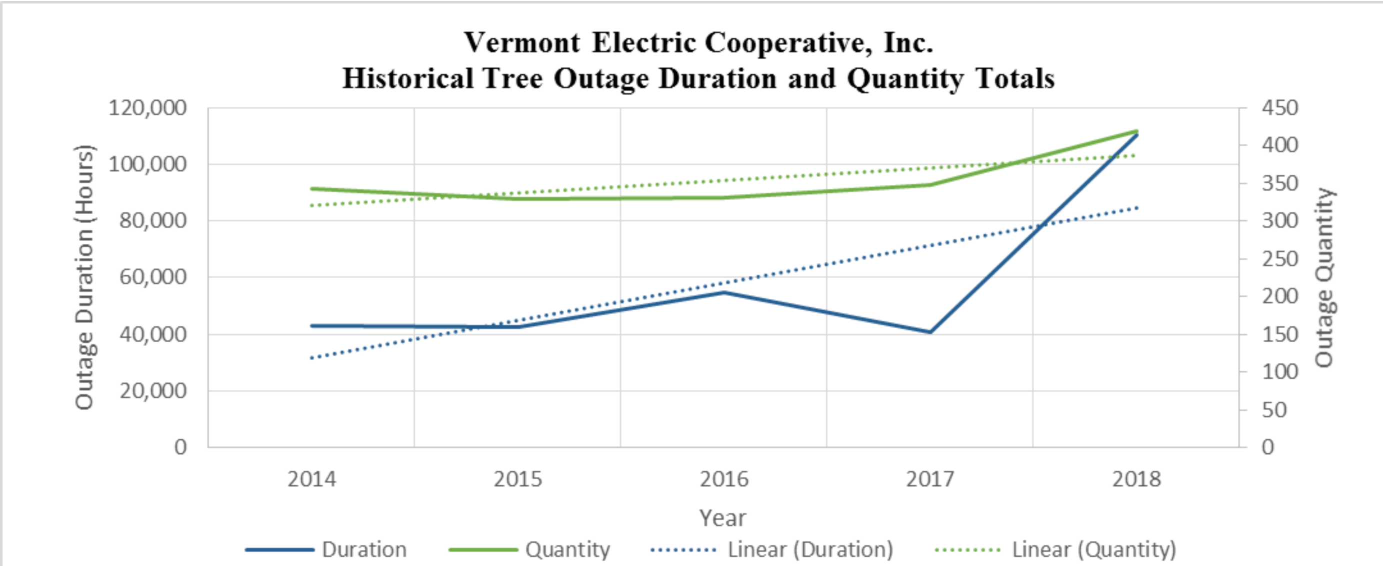



*Figure 4.8.1.A Historical tree outage duration and quantity totals*

While implementing a longer cycle initially allowed VEC to minimize rate impacts to the membership, the extended timeframe may have contributed to the increase in tree-related outages. Although trees falling in from outside of the ROWs still cause the majority of tree related outages, outages caused by trees growing in and by overhanging branches have begun to increase.

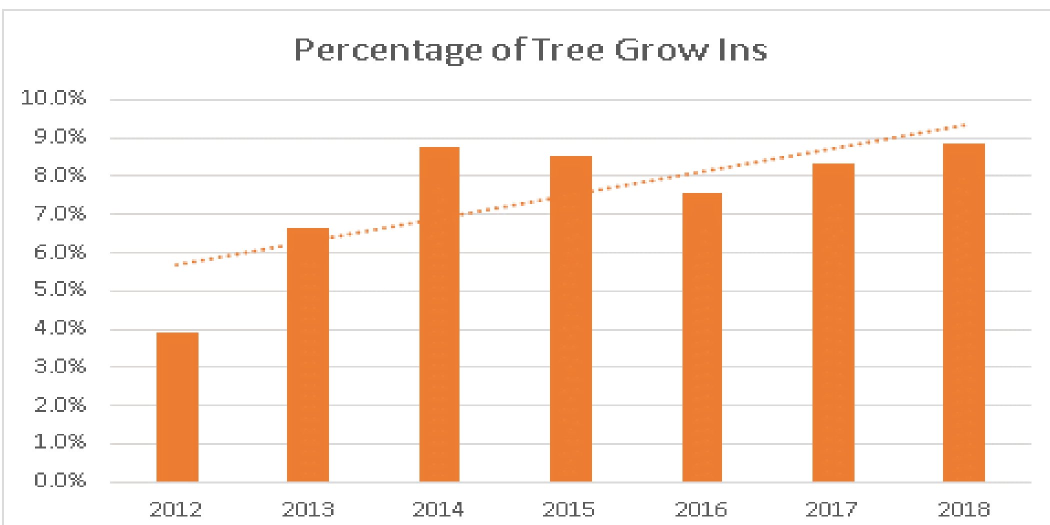



*Figure 4.8.1.B Percentage of tree grow-ins*

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 (member, public, employee, contractor)

- 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
- Member Service
- Adherence to national standards such as NESC and NRECA 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, located in Appendix-V, 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 rates and costs 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's entire service territory trimmed on a standard cycle (e.g., every six years), 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 vegetative growth rates. Further consideration for this blended cycle explored the following criteria:

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

**<u>VTFW Rare, Threatened, and Endangered Species</u>**

During the summer of 2018, VEC contracted with a qualified environmental firm to conduct a survey and document existing Rare, Threatened, and Endangered (RTE) species occurrences, as identified by VT Department of Fish and Wildlife's (VTFW) Natural Heritage Information Program, that intersect VEC's Transmission System Right-of-Way corridor. This project has allowed VEC to strengthen general awareness around existing regulatory standards, better understand the presence of both animal and plant RTE species along VEC's utility corridors, and enhance our working relationship with the VTFW. The data will be shared with VTFW and will then be utilized by VTFW to update RTE polygons. The project results, and the efforts built upon them, provide for the development and implementation of effective and efficient vegetation management and line operation strategies moving forward.

**VTFW Licensing**

Additionally, VEC is working through the administrative approval process with the VTFW department to support proactive vegetative maintenance work on state owned lands. The goal of this improved licensing effort is for a more streamlined approach to routine maintenance work and an elevated working relationship with both VTFW and VT Department of Forests, Parks, and Recreation managers and biologists at the state and regional level. This streamlined approach removes administrative lag and allows VEC to remain on its regularly scheduled routine ROW maintenance.

**Emerald Ash Borer**

A significant impact to VEC's Vegetation Management program is the Emerald Ash Borer (EAB). Vermont has confirmed the emerald ash borer is within its borders and specifically in VEC service territory in Grand Isle. 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 5% 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. It costs an average of approximately $144 per tree removal, and utilities that have already experienced the impacts of EAB infested ash trees costing more than two times the normal cost to remove. Based on this information, VEC estimates the cost to remove all ash trees in danger of striking VEC lines to cost $216,000,000 over five years. VEC requested federal appropriations to develop a formal EAB Response Plan and Mitigation Program. This plan includes training and education/outreach ($50,000); a system wide 100 percent ash inventory with current strike capability, tree condition, location and mapping ($650,000); ash hazard tree removal ($196,500,000); and utility arborist consultant services (equivalent to a full time employee) for data collection/analysis for five years ($1,000,000). It is unknown when or if this funding will be available to VEC or other distribution utilities in Vermont. However, VEC is pursuing state and federal funding opportunities including grants.

*Figure 4.8.1.C 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 been found in three Vermont counties and will spread over time, as there is no known treatment or 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 will include 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, all distribution utilities, and Vermont state organizations who are studying this issue.

## System Protection

VEC designs its power system protection to automatically detect faults that occur on the system and sectionalize or isolate the faulted parts 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. VEC utilizes the following system protection equipment that is designed to automatically coordinate with one another to sense system faults and sectionalize or isolate the system closest to the faulted parts:

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

The design settings of these equipment types aim to reduce the time of fault exposure to the shortest possible in order to improve worker and public safety, minimize 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.

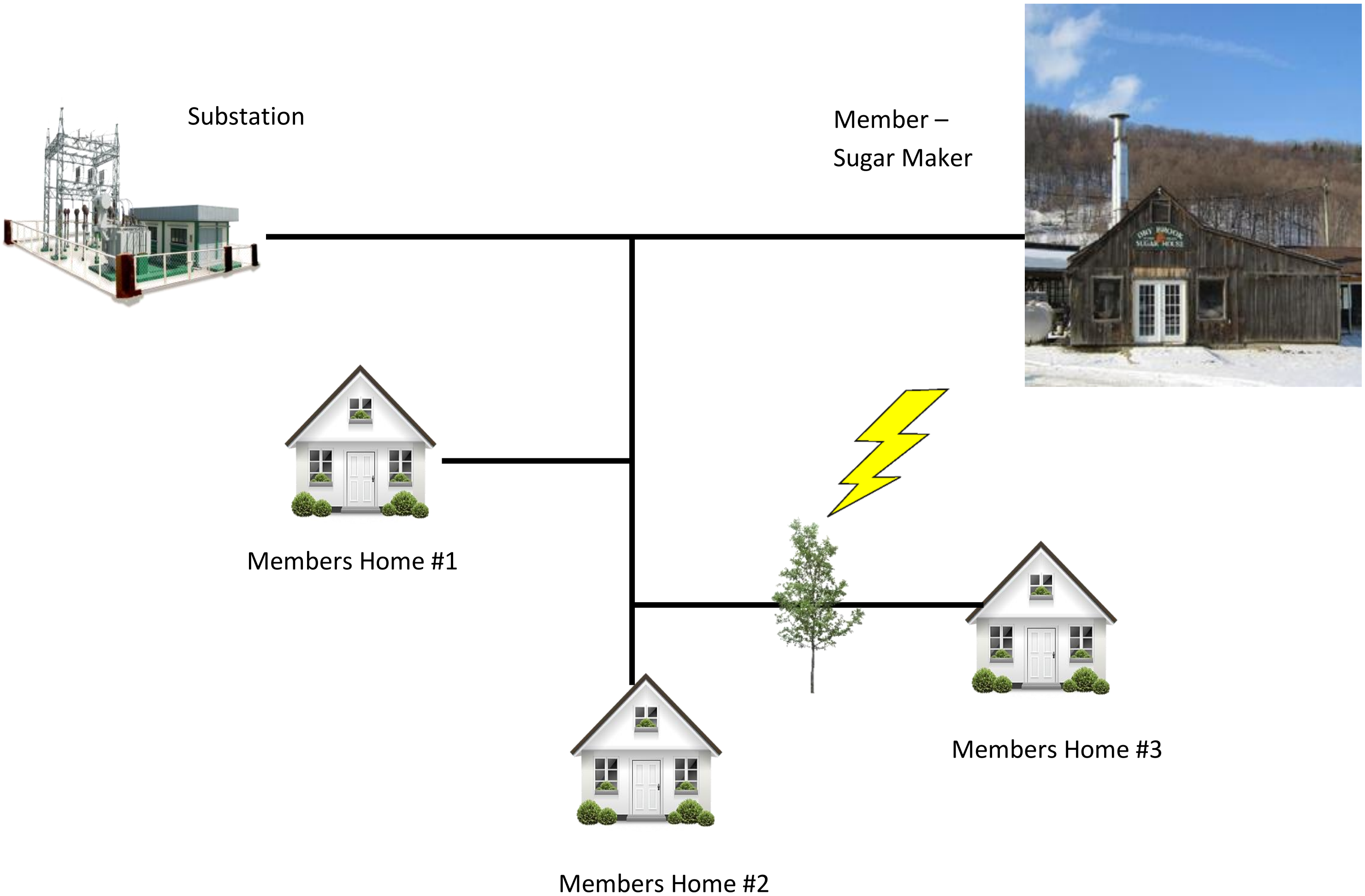



*Figure 4.8.1.D Tree falling on line near member #3*

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.

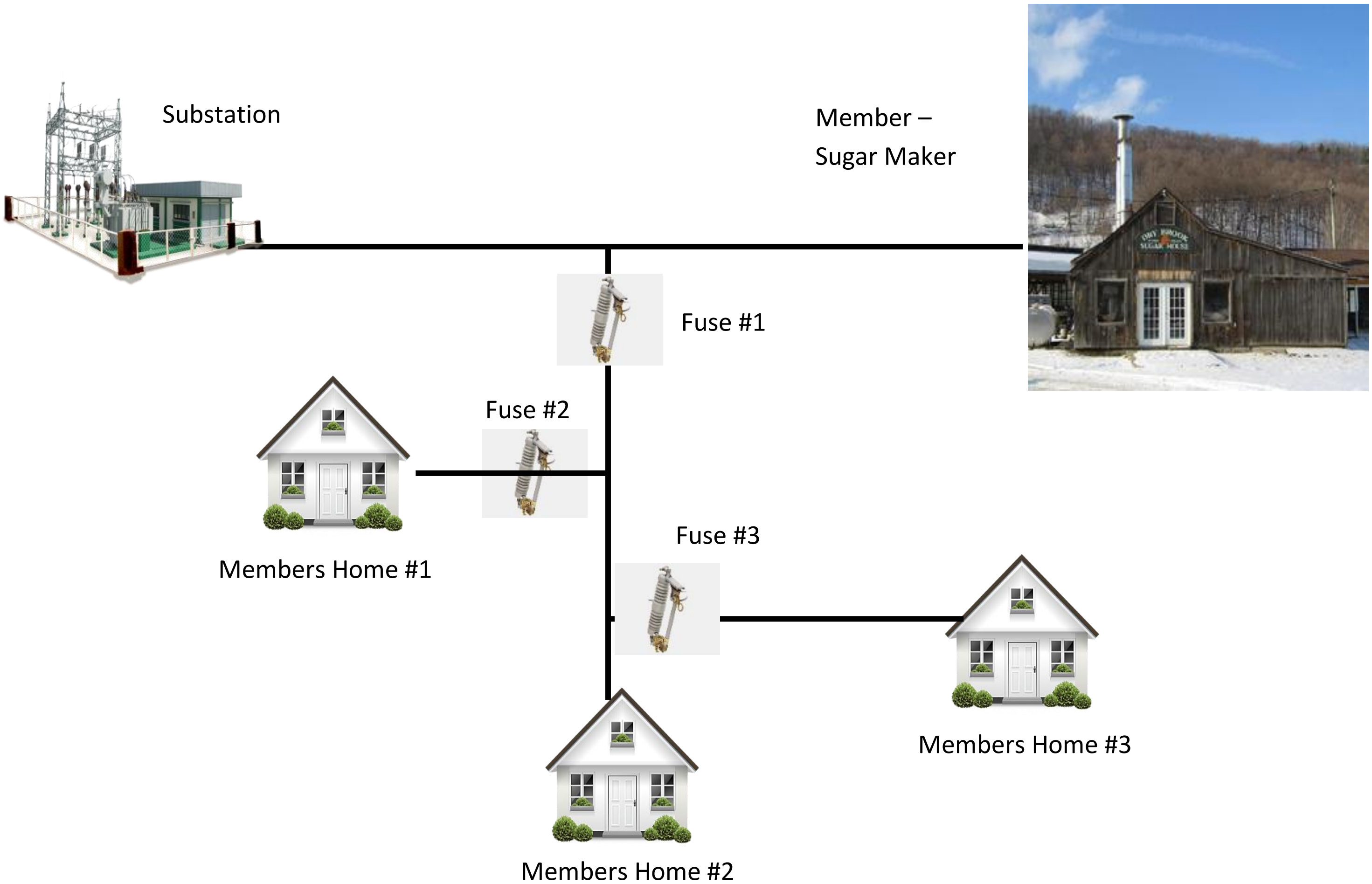



*Figure 4.8.1.E Adequately sectionalized circuit*

Extensive studies of overhead distribution systems have established that 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 of opening and reclosing helps keep these temporary type faults from becoming a longer outage. An example of a temporary fault would be an animal or bird that contacts 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. The vast majority of 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 in an effort to better sectionalize outages and minimize the quantity of members affected by them. An example of this is provided below:

**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. In addition, VEC utilizes overcurrent protection to maximize load current, allow for cold load pickup and 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 within 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 in an attempt 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.

## Wildlife Protection

In North America, around 20 percent of power outages are animal or bird caused. In 2017, wildlife related outages account for nearly 20 percent of all VEC outages. 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.

On its distribution system, VEC adds wildlife protection to all new and replacement reclosers, regulators and transformers. In addition, VEC adds wildlife protection on all new substation reclosers, switches, regulators, and transformers.

VEC recently updated its standards for distribution transformer wildlife protection and now uses a new 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, and Durability Performance of Wildlife Protective Devices on Overhead Power Distribution Systems Rated up to 38 kV) and UL94 V-0 flammability.

The older style protection had a lower cost but it did not prevent birds from pursuing bugs inside the arrester protection cap, which causes outages. VEC also identified that the porcelain gap arresters still have an exposed electrical component.  VEC eliminated this issue by changing the practice to replacing the gap arrester with a new polymer with a covered lead.

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. VEC recently established an avian protection plan that involves patrolling three phase main lines and removing nests identified on these.  If the osprey comes back to same location, VEC sets a pole away from our distribution line to allow the osprey to build their nest while not affecting the power system.

## Fault Indicators

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. Fault indicators. In general, VEC installs fault indicators where power lines cross the road in areas that are difficult to access.

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.

## Damage Prevention Plan

VEC is a member of Dig Safe and adheres to their procedures for the mapping, marking of our facilities and locating of our facilities. We contract locate services to USIC and map all transmission, distribution primary and secondary underground facilities on our GIS. VEC does not map member owned secondary systems but our underground locating contractor, VSIC, will locate them when appropriate. In addition to mapping, VEC marks new underground systems with marking tape and above ground stakes.

VEC utilizes an internal operating procedure (OP-26) that identifies procedures and protocols for marking, locating VEC facilities and the protocols for VEC excavating work. VEC’s procedure follows PUC Rule 3.800 and V.S.A. Chapter 86 to guarantee the reliability of service to our members, avoid damage to VEC underground facilities and ensure the safety of our employees and the public. VEC OP-26 can be found in Appendix-K

## Opportunities for 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 high priority within the capital project prioritization process. 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.

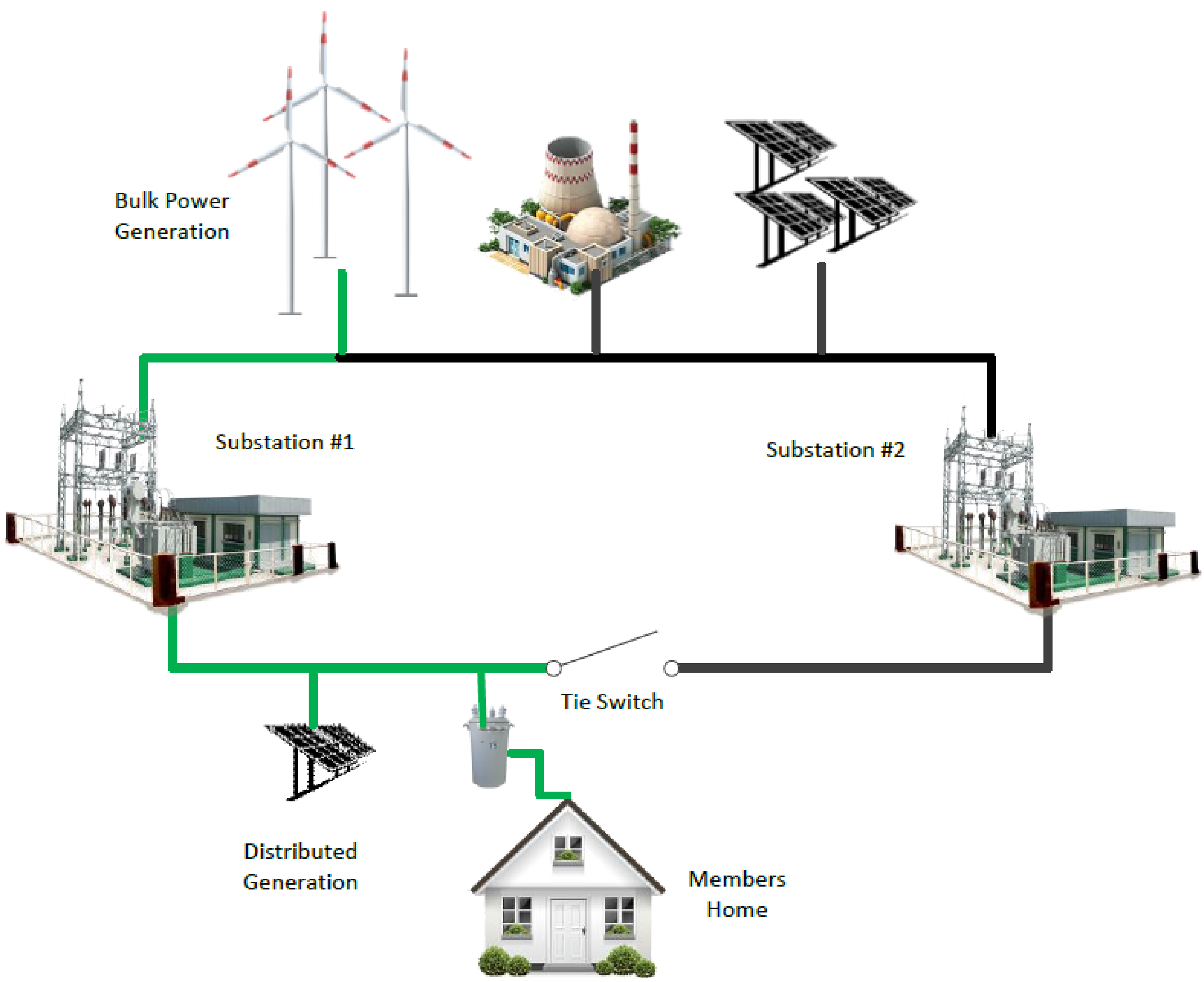



*Figure 4.8.1.F Normal configuration without feeder backup utilized*

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

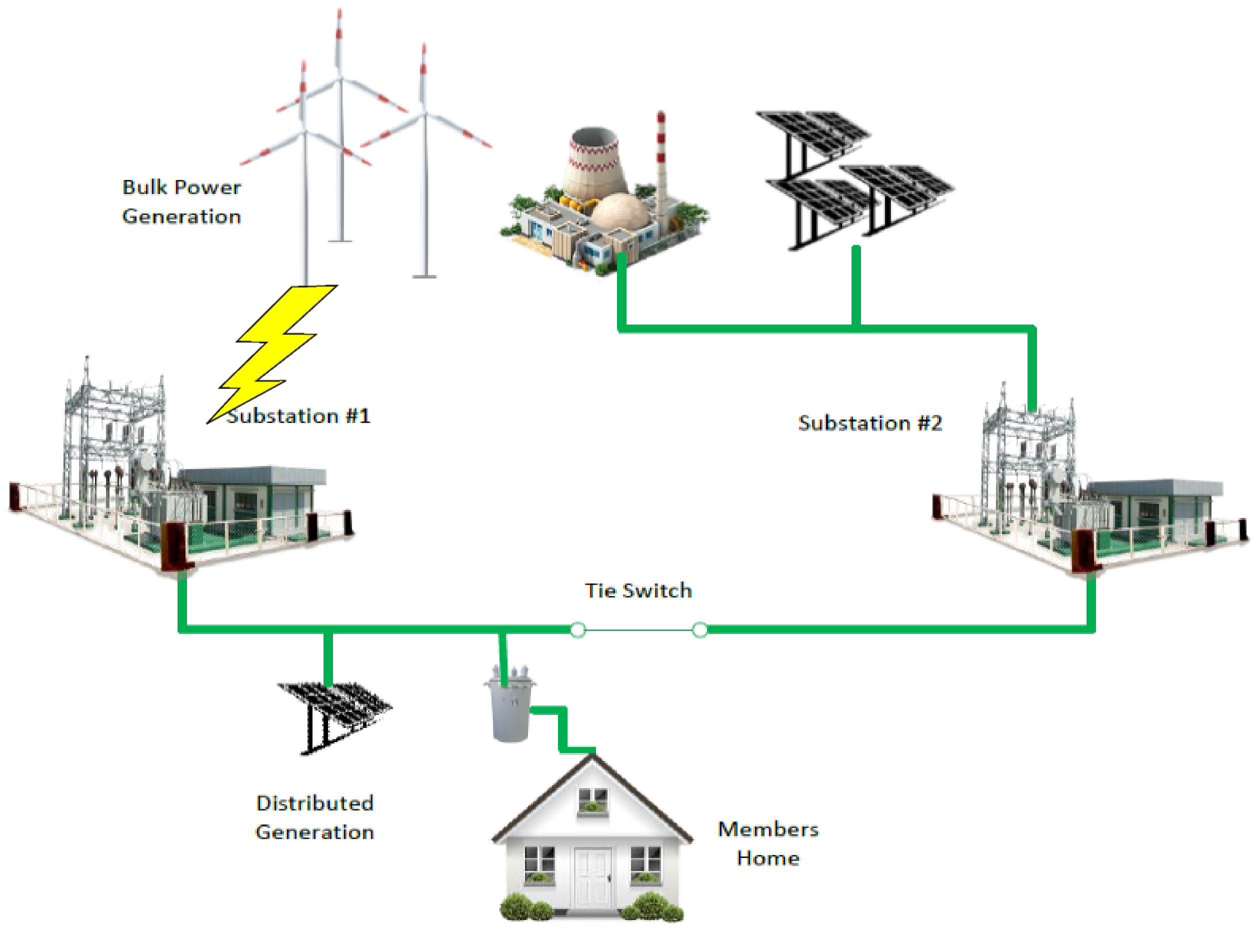



*Figure 4.8.1.G Transmission outage member restoration using feeder backup*

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 (where lines connecting two circuits or substations are 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 and thereby increasing the distance of the line further.
- **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.

## SCADA and Motor-Operated Tie Switches

In order to enable feeder backup there are typically required system upgrades such as reconductoring or new tie lines. VEC considers installing motor operated and SCADA controlled tie switches when conditions warrant and appropriate.

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.

## 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 this is 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 this:

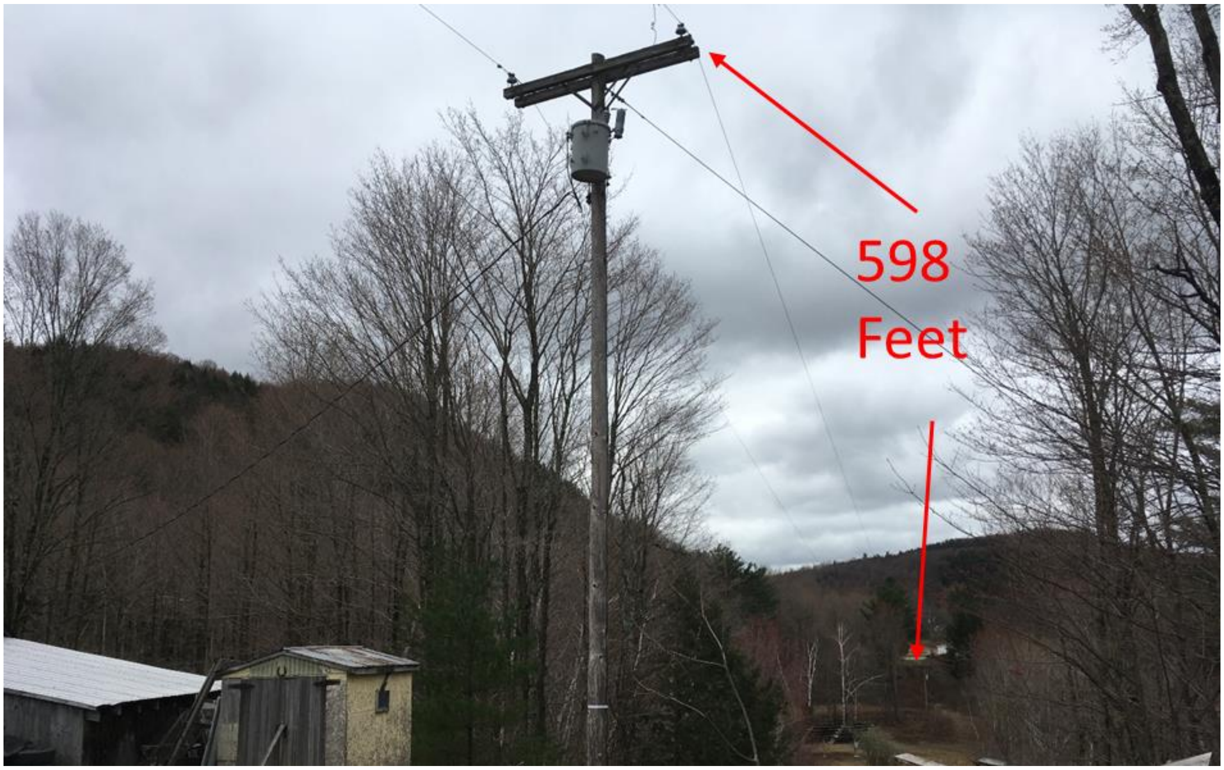



*Figure 4.8.1.H   598-foot span in Richmond*

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

**Horizontal to Vertical Corners**

Another issue that may occur is a shortage of clearance between the neutral and primary conductors on a vertical corner structure where the primary may cross directly over each other (multi-phase) or the neutral (single-phase) close to the mid-span on each side of the corner pole.  The following photos show examples of vertical and horizontal spacing:

Figure 4.8.1.I Vertical spacing

Figure 4.8.1.J Horizontal spacing

During a transition from horizontal to vertical or vice versa, the conductor will cross close to mid-span. Typically, the neutral conductor, which is not in the vertical plane on a tangent structure, is clamped to the pole on a corner structure causing the primary to cross directly over it. In some cases, the distance between the conductor and the neutral may be inadequate with additional conductor stretch caused by repeated outage events. In this case, VEC would stand off the neutral conductor on the corner poles so they do not cross one another.

## Maintenance Plan

As discussed in the Maintenance section of this document, VEC is initiating its comprehensive maintenance plan in 2019 to enhance reliability and proactively reduce preventable outages for VEC's members.

VEC has hired contract resources to assess and gather data on the following:

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

VEC personnel will perform assessment on special equipment such as reclosers, voltage regulators, and substation equipment. VEC Engineering and Operations will review gathered data and inspection results throughout the five--year period. VEC hired 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.

VEC expects the maintenance program to pay for itself through additional revenue via identified unauthorized third party attachments, street light audits, and a 20 percent reduction in outage events. For more information, see the Maintenance Plan in Appendix-L.

## Review of SAIDI > 1 minute

In 2019, VEC began reviewing all outages with a SAIDI (System Average Interruption Duration Index) value of greater than 1 minute. SAIDI is the average outage duration for each member on VEC's service territory. SAIDI is very similar to CAIDI with one key difference. SAIDI utilizes the total number of members connected to the system. CAIDI is only averaged by the members interrupted in each outage event.

These SAIDI reviews include an analysis of operating procedures, lineman efficiency, system protection, and potential system upgrades to increase operational effectiveness moving forward and hopefully reduce the likelihood of future outages.

## Worst Performing Circuits

VEC has broken 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 has provided a list of worst performers based on a five-year average (2014-2018) but utilizes the 2018 data to develop projects and mitigate these outages.

**Worst Performers Average (2014-2018)**

| Rank | Circuit Name | OUTAGES | HOURS | SAIFI | CAIDI | SAIDI |
|---|---|---|---|---|---|---|
| 1 | South Hero 1A | 70 | 3,659 | 1.78 | 0.74 | 5.10 |
| 2 | South Alburg 1A | 65 | 4,086 | 1.97 | 0.58 | 4.73 |
| 3 | Burton Hill 3A | 49 | 11,424 | 7.60 | 0.39 | 16.31 |
| 4 | South Hero 3A | 50 | 2,141 | 1.59 | 0.82 | 2.76 |
| 5 | Sheldon 1A | 50 | 2,282 | 2.54 | 0.63 | 4.65 |
| 6 | Hinesburg 3A | 52 | 10,327 | 5.18 | 0.51 | 9.19 |
| 7 | Irasburg 3A | 38 | 4,205 | 3.65 | 0.64 | 4.87 |
| 8 | West Charleston 1A | 36 | 4,657 | 9.48 | 0.54 | 8.89 |
| 9 | Cambridge 1A | 35 | 4,614 | 4.44 | 0.56 | 6.38 |
| 10 | Hinesburg 1A | 34 | 8,262 | 8.35 | 0.45 | 9.11 |

*Table 4.8.1.A 2014-2018 average worst performing circuits*

**Worst Performers in 2018**

The chart below displays the worst performing circuits in 2018.

| Rank | Circuit Name | OUTAGES | HOURS | SAIFI | CAIDI | SAIDI |
|---|---|---|---|---|---|---|
| 1 | South Alburg 1A | 100 | 6,185 | 0.07 | 2.19 | 9.63 |
| 2 | Sheldon 1A | 80 | 5,809 | 0.11 | 1.35 | 9.04 |
| 3 | South Hero 1A | 80 | 2,499 | 0.1 | 0.65 | 3.89 |
| 4 | Irasburg 3A | 68 | 10,268 | 0.1 | 2.7 | 15.99 |
| 5 | Burton Hill 3A | 66 | 8,826 | 0.1 | 2.19 | 13.74 |
| 6 | South Hero 3A | 64 | 4,165 | 0.08 | 1.32 | 6.48 |
| 7 | North Troy 3A | 57 | 16,285 | 0.1 | 4.05 | 25.35 |
| 8 | Hinesburg 3A | 56 | 9,950 | 0.09 | 2.73 | 15.49 |
| 9 | Irasburg 1A | 52 | 11,156 | 0.08 | 3.59 | 17.37 |
| 10 | Cambridge 1A | 52 | 3,016 | 0.06 | 1.42 | 4.70 |

*Table 4.8.1.B 2018 worst performing circuits*

In 2018, VEC invested over $500,000 in capital improvements on its 2017 worst performing circuits. These capital improvements included the installation of over 700 new animal and arrestor guards, 40 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 2017 and 2018. VEC has approximately 110 additional miles scheduled for maintenance in 2019 and approximately 210 miles scheduled for maintenance in 2020. Additional prescribed maintenance and hazard tree removal will also take place to address any safety or reliability concerns.

The worst performing circuit table above contains all outage, including capital improvements, experienced by members on those circuits. The table below removes outages associated with capital improvements and is the table utilized by VEC to determine which circuits will see reliability improvement projects. VEC intends to prioritize reliability improvement projects, which generally include reconductoring with tree wire, adding mid-span poles, additional feeder protection, and line relocations, for the circuits listed below.

| Rank | Circuit Name | OUTAGES | HOURS | SAIFI | CAIDI | SAIDI |
|---|---|---|---|---|---|---|
| 1 | Burton Hill 3A | 66 | 8,826 | 0.1 | 2.19 | 13.74 |
| 2 | Sheldon 1A | 65 | 5,440 | 0.11 | 1.33 | 8.47 |
| 3 | Irasburg 3A | 63 | 10,255 | 0.1 | 2.71 | 15.97 |
| 4 | South Alburg 1A | 61 | 6,149 | 0.07 | 2.25 | 9.57 |
| 5 | South Hero 1A | 60 | 2,374 | 0.1 | 0.63 | 3.70 |
| 6 | North Troy 3A | 55 | 16,282 | 0.1 | 4.05 | 25.35 |
| 7 | South Hero 3A | 55 | 4,098 | 0.08 | 1.31 | 6.38 |
| 8 | Irasburg 1A | 52 | 11,156 | 0.08 | 3.59 | 17.37 |
| 9 | Cambridge 1A | 52 | 3,016 | 0.06 | 1.42 | 4.70 |
| 10 | Island Pond 46 2A | 50 | 9,117 | 0.1 | 2.41 | 14.19 |

*Table 4.8.1.C 2018 reliability improvement circuits*

#### "Three or More" Reports

In addition to the worst performing circuit analysis, VEC develops a quarterly "three or more" report. This report identifies all line sections that have had three or more outages within the last 365-day period. VEC uses three outages as a target due to VEC's SAIFI target of 2.5 outages per member system-wide. During the quarterly reviews VEC also reviews the occurrence of a line section on the last four "three or more" reports.

Each line section is prioritized by whether or not it is located on a worst performing circuit and then by the reoccurrence of the line section on the three or more report. VEC engineering reviews this information and develops capital or maintenance projects to attempt to mitigate these outages moving forward.

### 4.8.2 Assessment

The following section contains a detailed assessment VEC's 2014-2018 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 4.8.2.A VEC SAIFI and CAIDI SQRP goals*

VEC's System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) five year totals, excluding all major storms, were 1.82 and 2.11, respectively.

| | 2014 | 2015 | 2016 | 2017 | 2018 | 5 Year Total |
|---|---|---|---|---|---|---|
| **Total Members** | 38,305 | 38,780 | 38,372 | 38,538 | 38,982 | |
| **# of Members Out** | 56,326 | 72,071 | 65,406 | 66,137 | 91,374 | 351,314 |
| **Customer Hours Out** | 110,764 | 134,375 | 138,361 | 126,778 | 231,541 | 741,819 |
| **CAIDI** | 1.97 | 1.89 | 2.12 | 1.94 | 2.54 | 2.11 |
| **SAIFI** | 1.47 | 1.86 | 1.70 | 1.72 | 2.34 | 1.82 |

*Table 4.8.2.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 2014-2018.

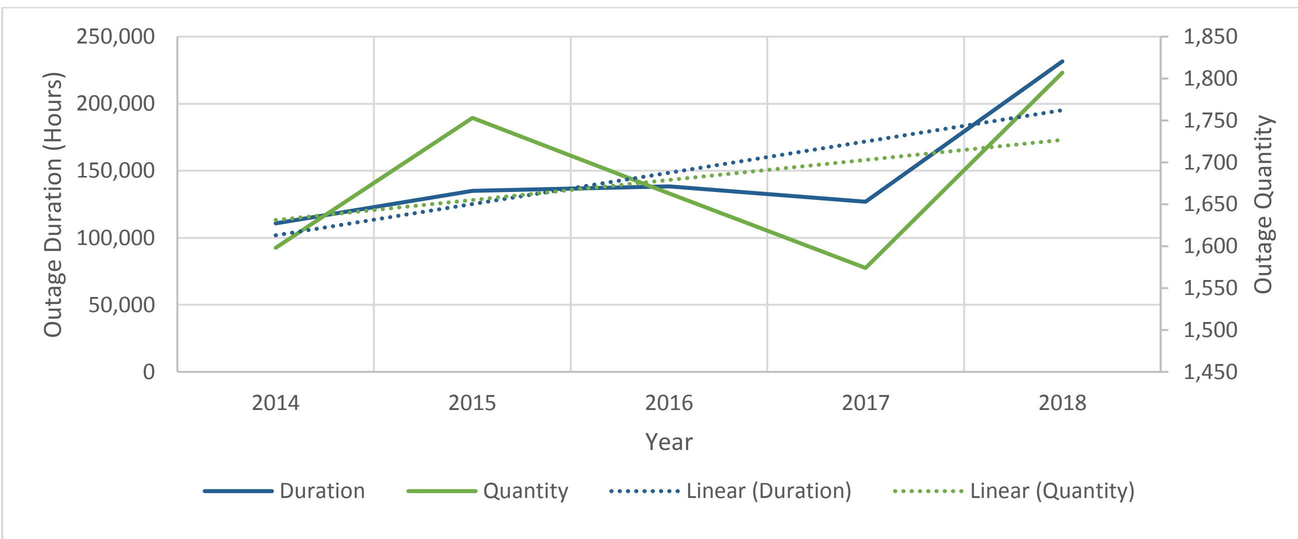



*Figure 4.8.2.A VEC historical outage duration and quantity totals*

Overall, VEC has seen a rising trend in both outage duration and outage quantity.

## Outage Quantity by Outage Cause

VEC experienced 1,592 outages in 2017 and averaged 1,647 over the four-year period between 2014 and 2017. The chart below identifies outage quantity by cause for 2014-2017.

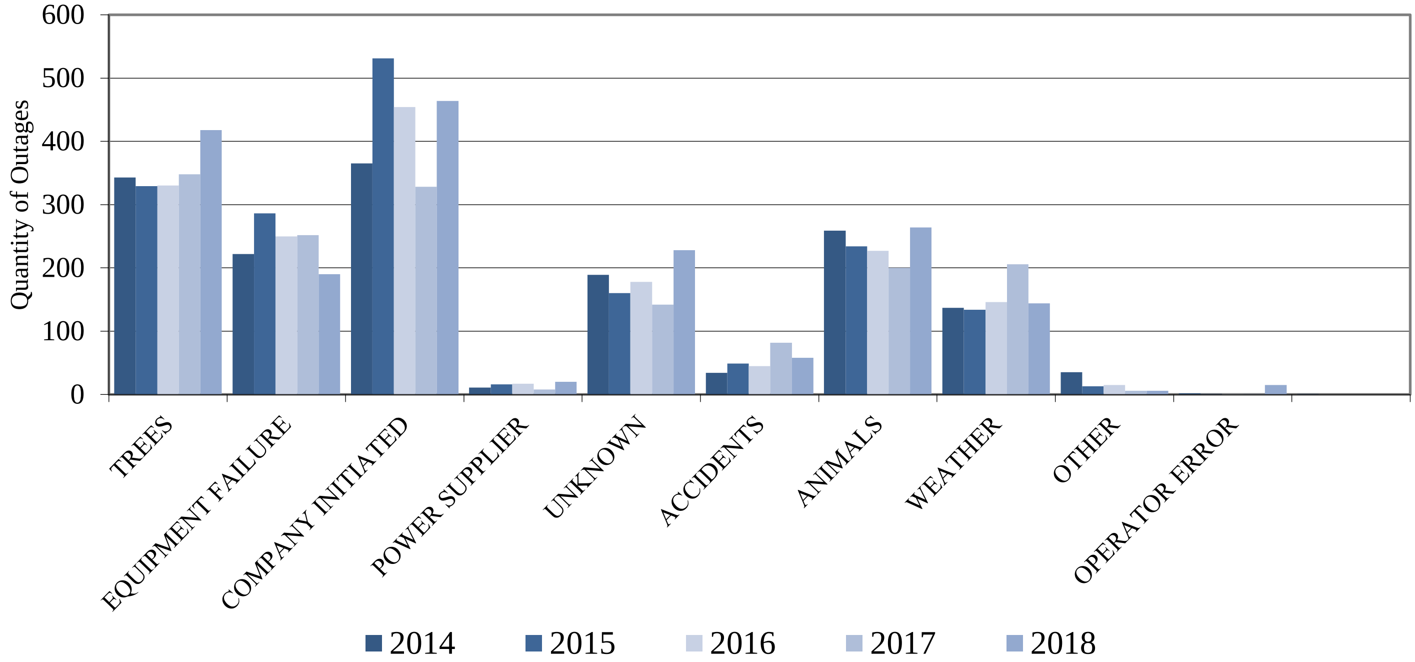



*Figure 4.8.2.B 2014-2018 quantity of outages by outage cause*

The chart below details the quantity of total outages by outage cause for 2018 as well as the five-year average.

| CAUSE | 2018 (Quantity) | Average (Quantity) |
|---|---|---|
| **COMPANY INITIATED** | 464 | 428 |
| **TREES** | 418 | 354 |
| **ANIMALS** | 264 | 237 |
| **UNKNOWN** | 228 | 170 |
| **EQUIPMENT FAILURE** | 190 | 245 |
| **WEATHER** | 144 | 153 |
| **ACCIDENTS** | 58 | 54 |
| **POWER SUPPLIER** | 20 | 15 |
| **OPERATOR ERROR** | 15 | 4 |
| **OTHER** | 6 | 10 |
| **NON-POWER SUPPLIER** | 0 | 0 |
| **TOTAL** | **1,807** | **1,679** |

*Table 4.8.2.C 2018 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. Around 32 percent (149) of the five-year average company-initiated outages were due to outages required for safety of VEC personnel when initiating capital improvements generally associated with reliability improvements. Another 17 percent (70) of these outages are related to tree removal when trees fall onto a power line but not cause an outage immediately. These company-initiated outages are generally shorter and completed with advanced notification. VEC works to reduce the impact of these outages to its members.

In regards to the tree-related outages, VEC was able to make significant, relatively quick improvements when it initiated its 12-year vegetation maintenance cycle in 2009. However, , we are no longer seeing a clear reduction in outages and will be moving to alternative treatment schedules over time to shorten the distribution vegetation maintenance cycle.

## Outage Duration by Outage Cause

VEC experienced 231,541 member hours out in 2018 and averaged 157,927 hours out over the four-year period between 2015 and 2018. The chart below identifies outage duration by cause for 2015-2018.

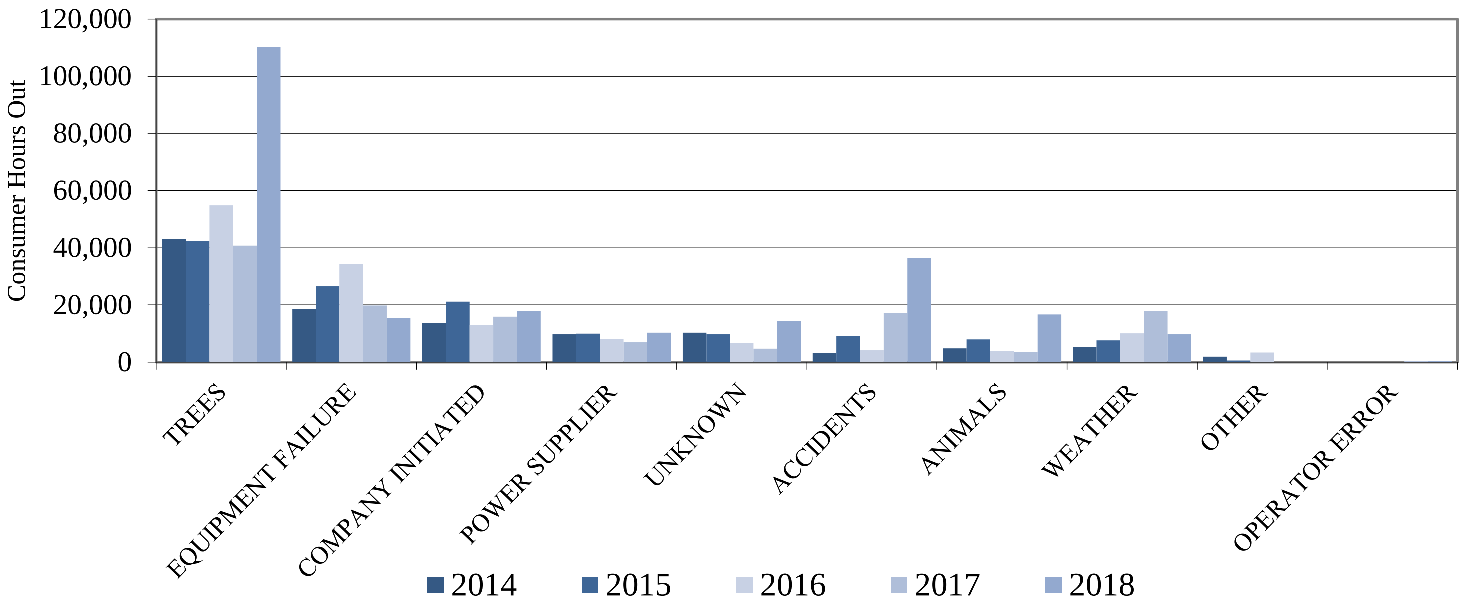



*Figure 4.8.2.C 2014-2018 duration of outages by outage cause*

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

| CAUSE | 2018 (Hours ) | Average (Hours) |
|---|---|---|
| **TREES** | 110,136 | 58.211 |
| **ACCIDENTS** | 36,448 | 14,015 |
| **COMPANY INITIATED** | 17,878 | 16,334 |
| **ANIMALS** | 16,676 | 7,332 |
| **EQUIPMENT FAILURE** | 15,452 | 22,954 |
| **UNKNOWN** | 14,389 | 9,144 |
| **POWER SUPPLIER** | 10,259 | 9,012 |
| **WEATHER** | 9,786 | 10.129 |
| **OPERATOR ERROR** | 499 | 186 |
| **OTHER** | 20 | 1,177 |
| **NON-POWER SUPPLIER** | - | 1 |
| **TOTAL** | **231,541** | **148,495** |

*Table 4.8.2.D 2018 and five-year average duration of outages by outage cause*

As shown in the above table, and consistent with outage quantity, tree-related outages are the primary driver with regard to outage duration. VEC also had an abnormally high number of long duration, high member count accident related outages in 2018.

## Major Events

Since 2014 VEC has experienced four events that qualified as “Major Storm” as defined in the VEC Service Quality & Reliability Plan (SQRP). As was 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% of the customers in a service territory are out of service due to the storm or the storm's effects; and
- At least 1% of the customers in the service territory are out of service for at least 24 hours.

The four major storm events are:

- **Winter Storm Damon (2014)**
    - Winter Storm Damon started on December 9, 2014 at hour 19:15 and ended on December 18, 2014 at hour 12:05. At peak, the storm caused over 23, 228 meters to be without power, and 637 outage events over the course of the storm. Heavy rainfall transitioned to wet snow on the eastern slopes of the Green Mountains dumping as much as 20” in places such as Jay Peak and the Eden/Lowell area. The water content of the snowfall was an unprecedented 5:1 water ratio. Utility contract meteorologist Roger Hill said, “This was the strongest Mesoscale banding of wet snow I’ve ever seen.”
- **Winter Storm Phillipe (2017)**
    - Winter Storm Phillipe started on October 30 at hour 02:00 and ended on November 6 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, including Vermont, very hard, causing broken poles and knocking down trees and branches onto lines all 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, or lines to touch (phase to phase or phase to neutral).