2024 Vermont Long-Range Transmission Plan

VSPC DRAFT

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1 Highlights

The following section summarizes some of this report's key assumptions, data points and conclusions. Of particular note, for the first time since 2015, load growth under one of the two forecast scenarios ("VT Roadmap") is projected to create grid reliability concerns within the Plan's 10-year horizon that could necessitate significant new transmission investment. Such investment can only be made after full, fair, and timely consideration of cost-effective non-transmission alternatives as required by Vermont law and regulation. More broadly, this report also offers a call to action for greater collaboration and focus on generation siting decisions – including storage – and on flexible load management to improve system resiliency, lower cost, and increase overall sustainability.

Peak demand is forecast to grow due to the electrification of heating and transportation

Over the next twenty years, summer and winter peak loads in Vermont are expected to grow mainly due to the electrification of transportation and heating. However, long-term forecasting can be uncertain, particularly since future load growth is influenced by public policy and human behavior—both of which are difficult to predict. That is especially true in this time of ongoing grid transformation. Mindful of these facts, this Plan offers two scenarios developed to cover a range of possible outcomes: the Continued Growth forecast scenario and the Vermont Roadmap forecast scenario. The Continued Growth forecast reflects a growth rate consistent with the current rate of technology adoption, e.g., electric vehicles and cold-climate heat pumps. The VT Roadmap forecast reflects a state statute-consistent uptick in the rate of adoption of electric vehicles and cold-climate heat pumps, thus aligning with Vermont's established policy objectives. These forecasts also reflect the effects of energy efficiency and the fact that solar PV generation does not contribute during peak hours in summer and winter due to the timing of peak loads occurring after dark. New this year is the assumption that 20% of electric vehicle charging will occur during the day at workplaces or public charging stations.

TABLE 1 – CONTINUED GROWTH AND VT ROADMAP LOAD GROWTH SCENARIOS

	All-time peak (year)	Historical 5-yr average	Continued Growth forecast scenario		VT Roadmap forecast scenario	
Season			**2033**	**2043**	**2033**	**2043**
Summer	1118 MW (2006)	935 MW	1085 MW	1226 MW	1195 MW	1330 MW
Winter	1086 MW (2004/05)	950 MW	1184 MW	1374 MW	1389 MW	1569 MW

Loads are projected to grow at a rate of 2.4% over the next 20 years, which is high but not unprecedented. In the 13-year period between 1993 and 2006, where the summer peak load increased from 819 MW to 1118 MW, the growth rate was 2.42%. In the first eight years of that period, the growth rate was closer to 2.6%. As noted later in the Plan, load management will be a critical component in our toolbox to achieve our emission reduction targets along with coordinated planning efforts, implementation of preferred solutions in a timely manner, and continuous adjustments of these practices as the load and generation patterns evolve over time.

The transmission system will experience reliability deficiencies due to peak demand growth near the ten-year timeframe, and load control may become less effective as loads continue to increase during the twenty-year planning horizon.

VELCO analyzed the transmission system using a methodology consistent with regional and federal standards. The electric grid is required to be designed to serve the highest demand during any hour, under stressed conditions and unplanned equipment failures. Deficiencies are identified when the performance of the system falls short of the requirements. Below is a summary of 2033 results by area.

TABLE 2 – SUMMARY OF BULK SYSTEM REGIONAL GROUPING & TRANSMISSION SOLUTIONS

Summary of bulk system Regional grouping & transmission solutions	Estimated transmission project cost	Screened in or out of full NTA analysis	Lead & affected distribution utilities
Northern area • Install a new 115 kV line between Essex and Williston • N-1-1 contingency causing thermal overload and voltage collapse exposure • Affected transformers: Queen City, Tafts Corner, Barre • Timing is 2032 based on winter VT Roadmap forecast	$120M Three X $11M	• Screened IN • 75 MW of load reduction in northern area by 2033 • NTA grows over time	*Lead*: GMP Affected: All VT
Northwest area – includes northern area • Rebuild West Rutland to Middlebury 115 kV line • N-1-1 contingency causing thermal overload • Affected transformer: Middlebury • Timing is 2029 based on summer VT Roadmap forecast	$215M $13M	• Screened IN • 80 MW of load reduction in northwest area by 2033 • NTA grows over time	*Lead*: GMP Affected: All VT
Central area – includes northwest area • Rebuild Coolidge - Cold River - North Rutland 115 kV line • N-1-1 contingency causing thermal overload • Affected transformers: N. Rutland, Cold River, Windsor • Timing is 2034 based on summer VT Roadmap forecast	$185M Three X $13M	• Screened IN • Keep load below 2033 load level in central area • NTA grows over time	*Lead*: GMP Affected: All VT
Southern area – includes central area • Rebuild NGRID Bellows Falls-Ascutney Tap 115 kV line and GMP Vernon Road to Newfane 46 kV • N-1-1 contingency causing thermal overload • Affected transformer: GMP Vernon Road 115/46 kV • Timing is 2034 based on summer VT Roadmap forecast	No VELCO estimate	• Screened IN • Keep load below 2033 load level in southern area • NTA grows over time	*Lead*: GMP Affected: All VT, NGRID
Statewide • Install a new 345 kV line between Vernon and Eversource Northfield, MA • N-1-1 contingency causing thermal overload • Affected transformers: Bennington • Timing is 2034 based on summer VT Roadmap forecast	$5M for VELCO portion $13M	• Screened IN • Keep load below 2033 load level in Vermont • NTA grows over time	*Lead*: GMP Affected: All VT, Eversource

For the first time since the 2015 Vermont Long-Range Transmission Plan, results indicate thermal and voltage concerns at the bulk system level, meaning the capacity of the transmission system will be exceeded as we approach year 10 of the planning horizon based on the Vermont Roadmap load forecast scenario. The Continued Growth load forecast scenario would postpone the timing of system impacts by six years or more. To describe the extent of these system impacts, the transmission system was divided into several geographic areas of concern. For example, in the northern area of concern, thermal overloads were observed in the summer and winter conditions tested, with the winter concerns being more severe. The concerns include the potential for a voltage collapse (blackout) at load levels beyond 2033, depending on capacitor bank dispatch and the subtransmission system performance. The criteria used to plan the electric system are set by the federal and regional reliability organizations, NERC, NPCC, and ISO-NE, including single-element and multi-element outages or contingencies. Reliability concerns were observed for N-1-1 contingencies, i.e. two succeeding outage events, at the transmission level, and they screened in for a full non-transmission alternatives (NTA) analysis. Therefore, NTAs can be applied between the first and second contingencies, as least initially and until NTAs are no longer viable.

At the "predominantly bulk" level, constituting those points where the transmission systems deliver energy to the distribution utility subsystems, analysis at the VT Roadmap forecast level identified several conditions where transformers and subtransmission lines would need to be disconnected to mitigate concerns caused by transmission outages. In some cases, these operating actions resulted in load shedding at levels less than the threshold necessary to allow regional funding of a transmission project solution based on current New England system planning rules. Most of these transformers were affected by N-1-1 contingencies, but the Queen City and Ascutney transformers were negatively affected by N-1 contingencies based on 2033 summer VT Roadmap analysis results. We propose to address the Queen City transformer issue as part of the northern area bulk system concern, and to address the Ascutney concern by shedding load, pending agreement with GMP, National Grid and Eversource. At higher load levels, transformers at Barre, Bennington, and North Rutland overload for N-1 contingencies.

At the subsystem level, the analysis flagged several locations requiring distribution utility review, which will determine whether grid reinforcements are necessary. This determination will depend on utility-specific criteria and the implementation of non-wires alternatives. If a utility determines that a system upgrade is the preferred solution, the utility will provide project cost estimates and demonstrate as part of the NTA process that NTAs are not feasible or cost-effective. In the analysis for this Plan, some of the known interactions between the subtransmission and transmission systems were concerning. While the distribution utilities neither plan nor design their system to multi-element or N-1-1 contingencies, it appears that this design philosophy is causing subtransmission deficiencies to cascade to the transmission system, and either cause or aggravate a transmission concern. We recommend upgrading overloaded subtransmission lines, particularly those that overload for a large number of transmission contingencies or that overload significantly. We also recommend the addition of transmission lines, when appropriate, to insulate the transmission system from the subtransmission system's limitations.

What follows the Long-range Plan Publication?

Consistent with the Vermont planning process outlined in the Docket No. 7081 Memorandum of Understanding https://puc.vermont.gov/sites/psbnew/files/orders/2007/7081mouwithattachments.pdf, following the Plan publication, a detailed NTA analysis will be performed during the next two years by the Affected Utilities and VELCO. Subsequently, when and if an NTA solution is selected, a cost allocation will be determined, and the NTA analysis will be summarized in a subsequent Plan appendix. Finally, the Affected Utilities will be responsible for implementing and funding the NTA solution.

The Lead Utility will manage the NTA study, will be the contact point for the reliability deficiency, and will provide updates to the VSPC. VELCO will support the NTA analysis process, including providing additional data regarding the reliability deficiency and other available information that would assist the NTA study team evaluate the adequacy and cost-effectiveness of the NTA solution. While ISO-NE is not subject to the 7081 MOU requirements, and is not required to participate in the NTA study, ISO-NE plays a critical role because ISO-NE is the transmission planner for Vermont. ISO-NE determines whether a transmission upgrade warrants regional funding, and whether a proposed NTA, aka a market response, sufficiently addresses the need. ISO-NE will treat an NTA solution as a resource that prevents the identification of system needs under specific conditions outlined in section 4.1 (f) of Attachment K of the ISO-NE open access tariff. At a high level, these conditions ensure the certainty of the market response.

VELCO having identified future reliability concerns does not mean that ISO-NE will immediately include the transmission upgrades in the regional system plan. ISO-NE uses its own planning process, load forecast, study methodology, and its own process for determining which upgrade should be pursued. If a reliability need is predicted to occur in more than three years, ISO-NE is required to conduct a request for proposal to seek competing transmission upgrade proposals from qualified transmission project sponsor, including the incumbent transmission owner, which is VELCO in this case. The results of the most recent ISO-NE study of the Vermont system were not as severe as those of the Long-range Plan. This does not mean that we should wait for the ISO-NE planning process to catch up before conducting the NTA study because we would run the risk of not complying with the Vermont planning process, which requires timely consideration of non-transmission alternatives. VELCO recommends completion of the NTA analysis. If the analysis shows that an NTA is viable and cost-effective, we recommend the implementation of the NTA solution to demonstrate the reliability of the NTA solution, which would allow ISO-NE to include the NTA in its forecast, which would in turn meet ISO-NE's need for certainty of proposed market solutions. More importantly, implementing the NTA solution will reduce the system deficiency risk and help VELCO meet the reliability gap until the ISO-NE planning process can identify the deficiency, although this may not happen soon because the ISO-NE planning process does not consider the subtransmission system limitations and interactions with transmission.

Load management is necessary to serve high electrification loads consistent with Vermont's total energy goals within the twenty-year planning horizon.

The analysis underlying this Plan was performed without crediting load control measures, such as flexible load management, storage, load shedding, microgrids, and other methods. This approach was adopted to identify system concerns, and determine the amount and location of the load that needs to be managed. Each transmission area of concern could be initially addressed with a non-transmission alternative or until load growth makes the NTA impracticable or too complicated. Taking the northern area of concern as an example, the statewide critical load level was determined to be about 1,300 MW, and the local area critical load was determined to be about 500 MW. The critical load is the load above which the reliability deficiency exposure exists. A review of the load control alternative at the winter 2043 VT Roadmap load forecast suggests that load control may be possible if it can be designed and implemented cost-effectively and reliably. Presumably, the transmission cost estimates will be the basis for assessing the cost-effectiveness of NTAs as part of the detailed NTA studies. However, when we consider that the entirety of the load that would need to be under control needs to reside within the northern area, it is doubtful that load control will continue to be viable. In addition to location, the effectiveness of a load management solution is highest if its characteristics match on the duration and frequency of the reliability concern, and can be adjusted as load and other conditions vary over time.

Careful, coordinated statewide planning is required to successfully integrate future distributed generation and storage without significant grid reinforcements.

Vermont public policies have been successful at encouraging investment in small-scale distributed generation, primarily solar PV. Based on data provided by the distribution utilities to ISO New England (ISO-NE), 500 MW of solar PV has been installed as of December 2023. This is in addition to approximately 90 MW of other distributed generation (DG) technologies. While certainly there are benefits to this generation, the proliferation of DG has started to stress parts of the system and has contributed to curtailment of larger renewable generators that are controllable by ISO-NE as the market administrator. Our analyses have found that transmission capacity will be exceeded if DG continues to be deployed in the same manner as today. Currently, DG projects are reviewed on a project-by-project basis without consideration to transmission system impacts.[1] If solar PV deployment continues without regard to transmission system capacity, the anticipated growth outlined in the current Vermont renewable energy standard (RES) and amounts beyond current targets will stress the transmission system to the point of causing additional curtailment of ISO-NE-controlled generation plants, or necessitate significant locally funded transmission upgrades. However, several options exist to mitigate these transmission concerns:

- DG deployment can be optimized to decelerate DG installations in areas with limited transmission capacity. The optimized geographical distribution, illustrated on page 73, demonstrates that transmission constraints can be minimized and significant transmission upgrades can be avoided by adhering to zonal limits.
- Vermont can also elect to curtail generation, but the financial and technical challenges need to be understood and addressed. Again, thoughtful siting of DG consistent with the optimized DG distribution map can minimize curtailment events.
- Storage is a solution category that includes devices or processes that store energy in one form during times of excessive energy production and later release that energy. If properly designed, operated, and located, storage can help alleviate system constraints caused by excess generation at certain times of the day.

Location is critical for storage, just as it is for generation and load. The ideal storage location to address excessive DG concerns is at a DG plant, similar to how a DG plant is better located at a load site to address heavy load concerns. The farther the storage is from a constraint, the less effective it will be in addressing it. In fact, if not operated optimally, storage could negatively affect the transmission system in similar ways to excessive DG depending on its location. For example, if storage is located south of a north-to-south constraint, the concerns will be aggravated during the charging cycle of the battery even if the energy absorption mitigates a local issue. Given this concern, it may be that the operational limitations that would be placed upon a hypothetical storage installation may make the project

[1] ISO-NE planning procedures require that studies be conducted when the aggregate amount of small-scale DG greater than 1 MW and less than 5 MW reaches 5 MW at a substation, or when the aggregate amount reaches 20 MW at a substation or local area. Currently, these thresholds have not been reached at any substation, but local areas are beginning to be saturated to a point where transmission level studies will be required in the near term. These studies may include steady state, short circuit, stability, and PSCAD analyses, and they do not apply to DG sized 1 MW or less.

undesirable to pursue. Studies should be conducted to evaluate system impacts of storage projects as is done for DG and large loads. Storage solutions can also be costly, and often require a stacking of economic benefits to remain an attractive option. In Vermont, these benefits may fall across a wide range of stakeholders, creating an additional barrier to effective cost-benefit analysis and overall funding viability of these projects.

Transmission will continue to be essential as we increase non-carbon-based energy consumption and production.

Traditionally, transmission has served to connect large generation plants to distant load centers where energy is consumed. In an increasingly decentralized electric grid, transmission's role is as critical today because the new distributed generation resources are intermittent, weather dependent, and out of alignment with daily peak demand. Distributed generation, predominantly solar PV, generates energy primarily from 7AM to 7PM, causing the Vermont summer peak demand to shift after dark. Without pairing solar PV with storage designed to provide a significant duration of energy, there is no incremental benefit from additional solar PV in serving peak demand. On cloudy days, or when covered with snow in the winter, solar PV production is notably lower. On the energy consumption side, the electrification of heating and transportation increases demand early in the morning and after dark, which does not align with solar PV production. The result of this mismatch is a reliance on out-of-state resources and the transmission system that imports the needed energy from our neighbors.

Including the behind-the-meter solar PV, the installed nameplate generation in Vermont amounts to about 1100 MW, roughly 10% higher than the current state peak demand. Even with this large amount of generation, since 2014 when Vermont Yankee was decommissioned, Vermont had consistently imported 100% of the time. That changed in May 2023, however, when Vermont exported approximately 60 MW during the low load/high solar PV generation period marking the first export since 2014. At other times, and particularly when capacity is needed at the peak hour, Vermont imports over 800 MW from its neighbors. We have also observed another phenomenon of late whereby the Highgate HVDC converter has exported energy to Hydro-Québec for the first time since 2014. This occurred during Québec's 2023 winter peak day and several more times during 2023, and which may be caused by energy prices instead of Hydro-Québec capacity shortages. Regardless, these notable reverses in power flow demonstrate how our system is changing.

We expect significant growth in renewable energy within the New York, Québec and New England control areas. This renewable generation will largely be intermittent and weather dependent, some of which will be non-dispatchable. The net result is excess energy during lower load periods. Studies have shown that new bidirectional ties will be needed to avoid curtailing offshore wind and other types of renewable generation. Given Vermont's unique position as the only New England state bordering both New York and Hydro-Québec, it is likely that additional transmission ties will be proposed to connect the Vermont system to Hydro-Québec and New York in the next ten years. Even as VELCO is working on at least two of these types of projects, they were not modeled in this Plan since their scope is unknown and they are quite uncertain.

ISO-NE 2033 Vermont Needs Assessment.

The ISO-NE 2033 Vermont Needs Assessment, completed in December 2023, identified a potential reliability concern within the ten-year horizon under winter peak conditions. This finding is similar to the long-range Plan finding for the so-called central area of concern. Although there were several differences in the study assumptions and approach, some of these differences can be reconciled in the next iteration of ISO-NE's Needs Assessment. However, certain differences such as ISO-NE's skepticism regarding the contribution of heat pumps to summer cooling loads will remain. This skepticism influenced ISO-NE's forecast approach, resulting in no growth in the Vermont summer peak. Specifically, ISO-NE modeled 942 MW for the summer evening peak compared to 1195 MW modeled in the long-range Plan summer VT Roadmap forecast scenario. Vermont stakeholders would need to provide sufficient data for ISO-NE to model cooling load. The 2017 Cadmus load study was deemed insufficient.

Coordinated planning is needed to fulfill the requirements of current Vermont statutes and policies.

In this Plan, we have noted the amount and location of load management that may address the identified reliability concerns. Storage clearly has a role to play if designed, operated, and located properly, and if cost challenges are addressed. The Plan also recommends that DG and other distributed resources, such as storage, be properly located to not exacerbate or create transmission constraints. Currently, there is no designated entity or group tasked to design and implement these solutions. The Vermont Public Utility Commission is expected to issue an order in 2024 convening a working group focused on flexible load management. Without additional collaboration and continued innovation, Vermont's electric grid will not be able to fulfill the requirements of current state statutes and policies.

Several important energy-related developments are underway but not reflected in this year's Plan.

Consistent with VELCO's mission and guidance from the Vermont Public Utility Commission, the last section of this Plan specifically addresses aspects of Vermont's Environmental Justice Act, which became law in 2022 but await further implementation. Beyond that notable exception, VELCO is aware of several important energy initiatives that could, and likely will impact the analysis results presented in this Plan but were not able to be considered due to the uncertainty over outcomes. These initiatives deserve mention nonetheless and they include:

- The fate of three proposed policy-driven transmission projects that impact Vermont: New England Clean Power Link, Twin States Clean Energy Link[2], and Alliance Transmission
- The outcome of a score of pertinent DOE Grid Resilience and Innovation Program (GRIP) applications
- Actual implementation results of the Affordable Heat statute enacted in 2023
- Reforms to the state's Renewable Energy Standard requirements under legislative consideration during the 2024 Legislative Session.
- Outcomes from the PUC-initiated docket creating a Flexible Load Management Working Group

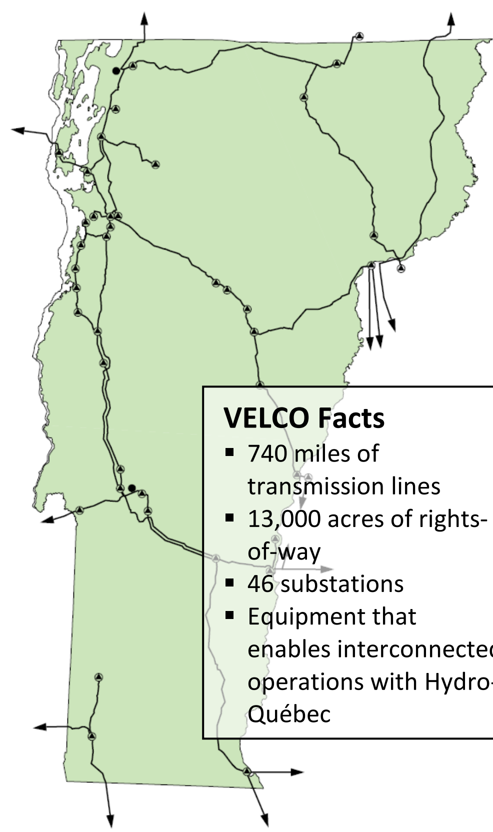
[2] The Twin States project appears to have been cancelled, but it is still in the ISO-NE interconnection study queue. The New England Clean Power Link project has been in the queue for nearly 10 years, and the Alliance project has not yet submitted an interconnection request.

2 Introduction

Vermont law (Act 61) and Vermont Public Utility Commission (PUC) order (Docket No. 7081) require VELCO to plan for Vermont's long-term electric transmission reliability, share our Plan with Vermonters, and update that Plan every three years. The Plan's purpose is to ensure Vermonters can see where Vermont's electric transmission system may need future upgrades, and how those needs may be met through transmission projects or other alternatives. Ideally, the Plan enables all manner of interested parties—local planners, homeowners, businesses, energy committees, developers of generation, energy efficiency service providers, land conservation organizations, and others—to learn what transmission projects might be required, and how and where non-transmission alternatives, such as efficiency and generation and load management, may contribute to meeting electric system needs at the lowest possible cost and impact.

VELCO's planning process is extensive and collaborative. The Vermont transmission system is part of New England's regional electric grid operated by ISO-New England (ISO-NE). ISO-NE is responsible for conducting planning for the region's high-voltage transmission system, under authority conferred on it by the Federal Energy Regulatory Commission (FERC). VELCO, along with the region's other transmission owners and according to established processes, participates with ISO-NE in its planning and system operations to meet mandatory reliability standards set by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and ISO-NE.

FIGURE 1 – VELCO TRANSMISSION LINES AND TIES TO NEIGHBORING STATES AND CANADA



VELCO Facts

- 740 miles of transmission lines
- 13,000 acres of rights-of-way
- 46 substations
- Equipment that enables interconnected operations with Hydro-Québec

The 2024 Vermont Long-Range Transmission Plan is the sixth three-year update of the Vermont 20-year transmission Plan, having been originally published in 2006 and updated in 2009, 2012, 2015, 2018, and 2021. Much has changed since 2006. ISO-NE began operating as FERC's designated Regional Transmission Organization for New England in 2005. Since then, ISO-NE has assumed the planning authority it was granted by FERC. Also during this period, more rigorous, binding performance standards for the high-voltage electric transmission system, and penalties for non-compliance, were authorized by Congress in response to the blackout of 2003, and subsequently adopted by NERC, NPCC, and ISO-NE in 2007. These changes required that Vermont's planning process coordinate closely with the regional planning work managed by ISO-NE.

In 2016, ISO-NE added tariff requirements to ensure fair competition among all qualified transmission project sponsors throughout the regional planning process. These requirements were enacted to ensure compliance with new procedures established by FERC through Order 1000, which introduced competition in the electric transmission sector. Today, VELCO receives system study information and is invited to provide comments at the same time as other members of the ISO-NE Planning Advisory Committee. In practical terms, ISO-NE no longer forms study teams that include affected transmission owners (TO) such as VELCO. If and when a system deficiency is found, ISO-NE does not work with the local TO separately from other stakeholders unless the system deficiency is identified as a time-sensitive need, meaning that the need is within three years of the conclusion of the study.

For the first time since 2014 and for the first time ever focused solely on Vermont and not including New Hampshire, ISO-NE has completed the 2033 Vermont Needs Assessment. This Assessment evaluated the reliability performance of Pool Transmission Facilities (PTF) and identified reliability-based transmission needs in the Vermont study area for the year 2033. Normally, the Vermont Long-Range Transmission Plan would use the results of this study for the first ten years of the long-range Plan horizon. In this long-range Plan, the most recent ISO-NE studies were determined to be inadequate for several reasons, including an incomplete summer peak forecast, an incomplete winter peak power flow model, and no recognition of the negative impacts of the subtransmission system's limitations on the transmission system.

By modeling system conditions specific to Vermont, the long-range Plan is able to meet Vermont-specific planning requirements. However, ISO-NE studies continue to be a necessary part of the Vermont Long-Range Transmission Plan process because only those system concerns categorized as regional can be addressed by transmission upgrades to PTF assets, i.e., those which are funded regionally based on load-ratio share with Vermont's load share at approximately 4% of the region's electric demand. VELCO's supplementary analyses frame Vermont's reliability issues in a manner that facilitates development of alternatives to transmission solutions consistent with Vermont legal and regulatory requirements. The ISO-NE Needs Assessment process and the Vermont Long-Range Plan process are thus not precisely in sync as is revealed in the load forecasts used in these studies. VELCO conducted analysis beyond NERC planning standard's 10-year horizon, analyzed the sub-transmission system[3], included the effects of renewable energy programs and budgeted energy efficiency, and considered non-transmission alternatives as appropriate, all consistent with applicable Vermont policy.

As noted in previous Plans, the electric grid is in the midst of a profound transformation driven perhaps primarily by the imperative to decarbonize the economy. The New England states, New York, and Québec, Canada, are on a path to electrify transportation and heating. Clearly, an enormous amount of renewable generation capacity will be needed to serve that additional load because: 1) peak demand is projected to increase significantly and potentially double; 2) energy generation at scale is projected to increase significantly; 3) and the current renewable energy technologies are intermittent and weather-dependent. Hydro-Québec expects its energy requirements to increase from 180 TWh[4] to 330 TWh by 2050 requiring about a 50% increase in new capacity. New York projects the winter peak to increase from 24,000 MW to 51,000 MW and energy to increase from 150 GWh to 230 GWh by 2050. New England projects the winter peak to increase from 21,000 MW to 57,000 MW by 2050. The most recent Vermont forecast in this Plan projects the winter peak to increase from 1,000 MW to 1,600 MW and energy to increase from 6 GWh to 8 GWh by 2043.

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[3] Sub-transmission includes those portions of the grid that are not considered "bulk system," i.e., they are above the distribution system level but at voltages below 115 kV, and their costs are not shared across the New England region. Generally, VELCO owns and operates the bulk system, and some distribution utilities own and operate sub-transmission.

[4] A TWh is a billion kilowatt-hours of energy, A GWh is a million kilowatt-hours of energy.

Each of those control areas (HQ, NYISO, and ISO-NE) will meet these new energy requirements through a combination of resources, including wind, hydro, efficiency measures, solar PV, internal and external energy purchases, and other grid-enhancing technologies as appropriate. With the influx of new generation capacity and energy coming on line, a significant portion of which will be intermittent, weather-dependent, and some non-dispatchable – meaning not following an ISO operator dispatch order to match electric demand – there will be times of excess energy that will require management. Energy management could include storage, curtailment, coordinated flexible load management, and perhaps the addition of energy intensive load, such as green hydrogen. New renewable energy will likely result in the retirement of thermal, nuclear, and other large-scale resources. Storage options could include batteries, technologies yet-to-be-proven, or proven technologies such as hydro reservoirs in Québec through existing and new necessary interties with New England and New York. Vermont's unique position as the only New England state bordering both New York and Québec, enables it to facilitate renewable energy transfers among these three control areas, and in so doing, benefit from the injection of energy in Vermont which would reduce Vermont's imports from AC ties with New York and New England. In addition, a new DC tie and associated inverter would strengthen the Vermont system, enabling a potentially necessary restart after a system-wide blackout due to the inverter's black start capability. While the Plan does not explicitly model any future DC ties to Québec or new AC ties to New York, we acknowledge that regional efforts to decarbonize the grid could have significant impacts on the Vermont system and, handled correctly, the Vermont system stands to gain from those developments in terms of reliability, resilience, and additional in-state renewable energy growth.

Beginning on page 43, this Plan shows the reliability needs on Vermont's high-voltage, bulk electric system.[5] Predominant bulk system issues and subsystem issues follow on page 54. The Plan discusses the potential to address these issues with non-wires solutions. The Plan also reflects the considerable uncertainties in today's environment due to the effects of changing energy policy and production trends. The Plan discusses the review of a base solar PV forecast and a high solar PV scenario that will hopefully facilitate greater statewide coordination of solar PV development. Lastly, the Plan addresses certain topics of interest to the Vermont Public Utility Commission who directed VELCO in an August 2023 memorandum to address specific areas including: greater visibility into VELCO's asset condition project queue (i.e. five-to-fifteen-year forecasts) and how right-sizing of new infrastructure can unlock longer-term grid opportunities; whether new grid enhancing technologies could obviate or defer grid buildouts; whether more storm-hardening projects are warranted; and, how VELCO's Plan will align with the goals, objectives, and requirements of Vermont's 2023 Environmental Justice Act.

[5] The bulk electric system, in the context of the plan, is the portion of the grid that is at 115 kV and above.

3 Issues addressed since the 2021 Plan

The 2021 plan[6] did not identify any major bulk system reliability concerns or predominantly bulk reliability concerns requiring mitigation. The Plan identified several subsystem issues to be further investigated by the distribution utilities. These subsystem issues can be found from page 34 to 36 of the 2021 Plan.

Other reliability issues were predicted to occur beyond the 15-year timeframe based on the 2020 load forecast. No mitigation was required for those issues due to the long horizon. They will continue to be monitored in every planning cycle, including this current Plan.

[6] https://www.velco.com/assets/documents/2021%20VLRTP%20to%20PUC_FINAL.pdf

4 Analyzing the transmission system

The power system has been called the most complex machine in the world. In every second of every day the power supply must match power demanded by customers. In areas where demand is greater than locally available supply, the electrical network must be robust enough to accommodate power imports from other sources. Where supply is greater than local demand, the system accommodates the export of power only up to its capacity, referred to as an export limit, and grid operators maintain export flows below system limits through various means including curtailment of generation. Since upgrades of electrical infrastructure generally require significant time and money, and modern society relies heavily on reliable power supply, planners must identify and address reliability concerns early without imposing unnecessary cost.

ISO-NE, VELCO, and other transmission system owners and operators are bound by federal and regional standards to maintain the reliability of the high-voltage electric system. System planners use computer simulation software[7] that mathematically models the behavior of electrical system components to determine where violations of standards may occur under various scenarios or cases.

Establishing what scenarios to study—like all planning—involves making assumptions about the future. Some of these assumptions are dictated by federal, regional, and state reliability criteria. Others reflect specialized professional skill, such as forecasting electric usage. Still others rely on understanding evolving trends in the industry and society. Some of these factors involve greater uncertainty than others and involve longer or shorter time frames. The following section discusses some major assumptions or parameters reflected in this transmission Plan.

4.1 Mandatory reliability standards

The criteria used to plan the electric system are set by the federal and regional reliability organizations, NERC, NPCC, and ISO-NE. These standards are the basis for the tests conducted in planning studies. Failure to comply with NERC standards may result in significant fines, and more importantly, unresolved deficiencies can lead to blackouts affecting areas in and outside Vermont. The transmission system is required to serve the highest demand in any hour, known as the peak load, which typically occurs during heat waves in the summer, or during severe cold spells in the winter. Currently, the Vermont system is dual-peaking, meaning that the peak hour can occur in either the summer or the winter. All assumptions underlying the peak load serving capability analysis reflect expected conditions at the Vermont peak hour, which does not always occur at the same time as the regional/ISO-NE peak hour. In recent years, the Vermont summer peak hour has occurred later at night, and the regional peak hour has started to drift to 6 PM. Sometimes, Vermont and the region can peak on a different day.

As required by the standards, planners measure system performance under three increasingly stressed conditions to determine whether the system will remain within mandatory performance criteria under various operating scenarios. Planners analyze the system under three kinds of conditions.

1. All facilities in service (no contingencies; expressed as N-0 or N minus zero).
2. A single element out of service (single contingency; expressed as N-1 or N minus one).

[7] VELCO uses Siemens PTI Power System Simulator for Engineering (PSS/E).

3. Multiple elements removed from service (due to a single contingency or a sequence of contingencies; expressed as N-1-1 or N minus one minus one).

In the N-1-1 scenario, planners assume one element is out of service followed by another event that occurs after a certain period. After the first event, operators make adjustments to the system in preparation for the next potential event. These adjustments can include switching in or out certain elements, resetting inter-regional tie flows where that ability exists, turning on peaking generators in importing areas, or backing down generators in exporting areas. In each scenario, if the software used to simulate the electric grid shows the system cannot maintain acceptable levels of power flow or voltage, a solution is required to resolve the reliability concern. The implementation of the preferred solution will depend on additional analysis that considers cost, feasibility, community impacts, and other factors.

4.2 Funding for bulk system reliability solutions

Since Vermont is part of the interconnected New England grid, bulk system transmission solutions in Vermont that are deemed by ISO-NE to provide regional reliability benefit are generally funded by all of New England's grid-connected customers, with Vermont paying approximately 4% of the cost based on its share of New England load. Likewise, Vermont pays 4% of reliability upgrades elsewhere in New England. Facilities subject to regional cost sharing are called Pool Transmission Facilities (PTF). The load growth related transmission reinforcement needs discussed in Vermont's Plans are eligible for PTF treatment provided they involve networked (PTF) transmission facilities and they are identified as reliability needs by ISO-NE. Transmission upgrades needed to support generation growth are not eligible for PTF treatment, and are funded by generation project developers. With respect to reliability concerns caused by distributed generation sized 1 MW or less, it is unclear at this time whether ISO-NE would consider those concerns as being eligible for regional cost treatment.

Regional sharing of funding for transmission projects has been present in New England for several decades. Since 2008, through the creation of a regional energy market called the Forward Capacity Market (FCM), providers of generation and demand resources (energy efficiency and demand response) are compensated through regional funding for their capacity to contribute to meeting the region's future electric demand. These capacity supplies may reduce the need to build new transmission infrastructure if properly located with respect to transmission system capacity and local load levels. Capacity and energy resources are part of a competitive market, and transmission upgrades necessary to connect new resources are funded by project developers, consistent with the requirements of ISO-NE's transmission tariff. In contrast, transmission upgrades needed to maintain reliable service to load are funded by all New England distribution utility customers pursuant to ISO-NE's transmission tariff. Separation between markets and transmission is a basic principle in current FERC rules, which creates a barrier to regional cost sharing of non-transmission alternatives, even when they are more cost-effective than a transmission upgrade. Vermont continues to advocate regionally for funding parity between transmission and non-transmission options to ensure the most cost-effective alternatives can be chosen to resolve a system constraint.

4.3 Planning horizon: 10 years vs. 20 years

By order, the Vermont PUC requires VELCO to plan using a 20-year horizon. Federal NERC standards and long-term studies performed in New England use a 10-year horizon. The longer the horizon of a transmission planning analysis, the more uncertain its conclusions due to uncertainties regarding load level predictions, generation, system topology, technological developments, changes to planning standards, and changes to public policy that impact how the transmission system will be used. This Plan reflects VELCO's 20-year analysis with the main focus on the first 10-year period through 2033. Results beyond 10 years were used to examine system performance trends, evolving system needs, the effects of increased demand, and longer-term solution options. This approach was reviewed and endorsed by the Vermont System Planning Committee (VSPC).[8]

In May 2022, FERC issued a Notice of Proposed Rulemaking (NOPR) in which it recommends a longer planning horizon. This recommendation can be found on page 20, section 92, Transmission Planning Horizon and Frequency of Docket No. RM21–17–000, where the FERC suggested that a longer planning horizon would allow planners to capture the longer-term benefits of addressing transmission needs driven by changes in the resource mix and demand. Longer-term planning would not necessarily result in additional upgrades, but would allow planners to make better decisions or to right-size solutions to meet near-term and uncertain longer-term needs.

4.4 The scope of the Plan

The Vermont planning process allows VELCO to identify reliability concerns early so that cost-effective non-transmission alternatives are given full, fair, and timely consideration. In cases where NTAs are not feasible or cost-effective, transmission projects are implemented. Projects covered in this Plan include transmission system reinforcements that address transmission system reliability deficiencies as required by Vermont law and regulation as articulated in Title 30, subsection 218c of Vermont Statutes and the PUC Docket 7081[9]. As such, the Plan may not include all transmission concerns that must be addressed in the coming period. VELCO sought input in multiple phases during its analysis to identify all load-serving concerns that may require system upgrades; however, some concerns may not have been identified due to insufficient information, unforeseen events, new requirements, or the emergence of new information.

In addition, from time to time, VELCO must make improvements to its system to replace obsolete equipment, make repairs, relocate a piece of equipment, or otherwise carry out its obligation to maintain a reliable grid. While VELCO has a process in place for identifying degraded equipment before failures occur, equipment degradation sometimes happens unexpectedly, and VELCO addresses these concerns quickly. The Docket 7081 MOU does not explicitly require discussion of those asset condition or routine projects that are undertaken to maintain existing infrastructure in acceptable working condition. However, asset condition projects have become more common throughout the electric industry in recent years due to the advanced age of equipment. This is a similar phenomenon to the necessary refurbishment of roads, bridges, and other infrastructure. The Infrastructure Investment and Jobs Act[10] is a recognition of the need to repair, replace, and develop infrastructure countrywide.

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[8] The Vermont System Planning Committee facilitates a collaborative process, established in Public Service Board Docket 7081, for addressing electric grid reliability planning. It includes public representatives, utilities, and energy efficiency and generation representatives. Its goal is to ensure full, fair and timely consideration of cost-effective "non-wires" solutions to resolve grid reliability issues. For more information see https://www.vermontspc.com.

[9] Links to these documents are provided on the VSPC website at https://www.vermontspc.com/key-documents.

[10] https://www.congress.gov/bill/117th-congress/house-bill/3684.

Sometimes routine or asset condition activities require significant projects, such as the refurbishment of substation equipment and the replacement of a relatively large number of transmission structures to replace aging equipment or maintain acceptable ground clearances. Although Docket 7081 MOU requirements do not apply to these types of projects, VELCO is listing these projects for the sake of information. These projects are needed to maintain the existing system, not to address system issues resulting from load growth, and VELCO routinely shares plans for many of these projects with the VSPC as part of its non-transmission alternatives project screening process. The formal NTA screening tool employed in this process "screens out" projects that are deemed "impracticable" for non-transmission alternatives because they are specifically focused on resolving asset condition concerns.[11] Below are currently known VELCO asset condition assessments that may or may not lead to asset condition projects.

4.4.1 Substation condition assessments

VELCO's assessment of its substations identifies those elements of substations requiring repair or replacement. Sufficient equipment degradation has been found at the St. Johnsbury and Windsor substations, both of which require Section 248 filings to the PUC. The St. Johnsbury project was filed in November 2023, and the advance notice for the Windsor project was filed in January 2024. These refurbishment projects screened out of a detailed NTA analysis. As part of our regular work, VELCO routinely assesses our substations for necessary refurbishment. Below are other substations and equipment that we will evaluate in the next few years and may require mitigation.

Table 3 – Substation asset condition forecast

Transmission facility	Potential project timing
South Hero substation	One to three years
East Fairfax substation	One to three years
Cold River substation	One to three years
Vermont Yankee substation	Three to five years
Sand Bar phase shifting transformer	Three to five years
Granite synchronous condensers	Three to five years
Essex substation	Three to five years
Coolidge transformer	Five to ten years
Highgate converter	Five to ten years

4.4.2 Line condition assessments

VELCO's assessment of its transmission line structures identifies those structures requiring repair or replacement. Typically, VELCO replaces approximately 200 structures per year. Every effort is made to avoid or minimize negative impacts on system reliability, generation operation, and

[11] The two non-wires alternatives screening tools used by Vermont utilities are available on the VSPC website at https://www.vermontspc.com/key-documents.

environmental/community impact. For example, VELCO schedules line outages at a time that is less impactful, minimizes line outage durations, and even performs the work with the line energized when necessary.

VELCO assessed the nearly 17-mile K42 line between the Highgate and Georgia substations. Inspections indicated that 70% of the structures needed to be replaced. Following discussions with ISO-NE and New England stakeholders as part of the ISO-NE Planning Advisory Committee, it was concluded that the preferred mitigation approach is to rebuild the line instead of simply replacing the structures. This approach avoids approximately thirty line outage events during the refurbishment, reduces losses, improves system strength and reactive margin, allows more renewable generation to run under prevailing conditions, and enables renewable energy growth in a constrained area. The line loss reduction is due to the installation of a double-bundled conductor, and our analysis indicates that the benefits of the energy savings exceed the incremental cost of the second conductor. VELCO filed the Section 248 petition for the K42 line also known as the Franklin County Line Upgrade project in October 2023.

Several lines require extensive repair, and VELCO has started structure replacements on these lines. Two additional transmission lines have a large number of structures in need of replacement. In addition, because of known system benefits and the ability to address longer-term challenges associated with both electrification and new supply resources, these lines will be evaluated closely to determine whether a line rebuild would be a more suitable solution. These lines under consideration are the K54 115 kV line, extending from our Granite substation to the Barre substation, and the F206 230 kV line, connecting our Granite substation to the National Grid Comerford substation. The scope of work for these projects is unknown at this time, and the potential project timing is in about five years. VELCO will coordinate with ISO-NE to determine the best solution for Vermont and New England. At this time, we are not aware of any other line asset condition projects requiring a redesign.

4.4.3 Right-sizing of transmission infrastructure

Refurbishing degraded equipment or implementing a required upgrade presents an opportunity to replace equipment in a way that provides sufficient capacity to meet both short- and longer-term needs. Beyond addressing degraded equipment or mandatory upgrades, considerations such as storm hardening, compliance with current codes and standards, including safety, and accommodating communication and control needs are integral. Additionally, the need to anticipate and align with evolving transmission needs driven by climate and energy security policies that produce resource mix changes at scale must be considered. When refurbishing existing equipment, using the previously completed long-range transmission Plan analysis is the first step in considering right-sizing projects to meet longer-term needs. Almost certainly though, additional updated analysis will need to be performed to ensure our work reflects future policy or state or regional development.

Right-sizing also involves elements of the system that do not carry electrical energy. For example, a substation project can ensure that the substation control house is sized appropriately to house communication, protection and control equipment for one or more transmission lines, subtransmission lines, or transformers. Similarly, when a structure needs to be replaced, the new steel structure is sized to carry the VELCO standard conductor even in cases where the existing conductor is smaller than our current standard. This has been our preferred approach because the cost of steel structures is competitive, and steel is more resilient than wood in the face of severe weather events.

The decision to expand the scope of an asset condition project or a required system upgrade beyond the identified needs are informed by cost considerations, physical and aesthetics constraints, and prudency. Importantly, if the refurbishment or upgrade involves a pool transmission facility, expanding the scope beyond the minimum requirement may cause the additional cost to be assigned to Vermont exclusively instead of being shared with all New England customers, which affects the cost effectiveness of the scope expansion.

4.5 Study assumptions

When performing a study, system planners pay attention to three main parameters: (1) the electrical network topology; (2) generation; and, (3) the electrical demand, or load. Assumptions regarding these parameters serve as the foundation for the analysis underlying this Plan.

4.5.1 Electrical Network topology

The analysis models the electrical network in its expected configuration during the study horizon. Planners model new facilities and future system changes only if they have received ISO-NE I.3.9 approval or Vermont Section 248 Certificate of Public Good (CPG) approval, or have an approved power purchase contract because this provides a level of certainty that the facility will be in service as planned.

4.5.1.1 Assumptions regarding Plattsburgh-Sand Bar imports along existing facilities

The import of power from New York to Vermont over the Plattsburgh-Sand Bar transmission tie (PV20) was modeled at or near zero megawatt (0 MW) pre-contingency. System constraints in New York have led New York to request that studies assume 0 MW will flow over the tie, and that, under certain conditions, Vermont will export to New York. This assumption is more conservative in cases where insufficient capacity exists to serve Vermont load, but is also conservative from the New York perspective during heavy wind generation and lower load levels.

4.5.1.2 No elective transmission, or market-related projects in the Plan

ISO-NE's tariff includes a process for considering transmission projects needed to connect generation to markets and to increase the capacity of a transmission corridor that otherwise limits the ability to move electrical power from one part of the system to another. Such projects, needed for purposes other than ensuring reliability, are categorized as elective transmission upgrades, and are financed by the project developer, not end-use customers.

For this Plan, VELCO modeled current Elective Transmission Upgrades that are proposed as a means to import energy from New York or Canada to and through Vermont as out of service. This is due to the fact that although some of them have received ISO-NE I.3.9 approval, a determination of no adverse impact, their ultimate fate remains uncertain due to the complex economics and political interests involved. Two such projects have been withdrawn, and the remaining third project has postponed its in-service date several times. The price of energy at the receiving end of the proposed transmission projects would include both the cost of energy at the sending end and the cost of the transmission facilities that tend to disadvantage these projects when compared to most generation projects. Therefore, the financial viability of these projects is greatly improved if a buyer is willing to pay a premium for other benefits such as renewable energy, capacity value, and the ability to address system concerns, such as high short-circuit levels, unacceptable system voltages, and transmission constraints.

Additionally, the Elective Transmission Upgrades projects in question have been evaluated by ISO-NE as a part of their system impact studies that included a comprehensive assessment of both import and export conditions. VELCO reviewed and provided feedback that was incorporated in these studies. The Company determined that the study work performed was adequate to ascertain the Elective Transmission Upgrades impacts to the Vermont transmission system. These system impact studies identified the need for several system upgrades to address system concerns that would arise if the Elective Transmission Upgrades were constructed.

Recently, there has been a substantially increased level of interest in offshore wind generation projects. ISO-NE has performed offshore wind integration studies at the request of the New England states and other stakeholders, and those studies indicate that there will not be sufficient load to consume the wind energy during low-load periods. It is possible that this offshore wind generation will lead to the retirement of existing generators, and this might aggravate the energy security challenge in New England. In addition, it has become clear from the results of the ISO-NE studies that two-way energy exchange is becoming even more essential between New England its neighbors. Therefore, the tie lines between New England and New York, as well as between New England and Canada need to be reinforced so that excess renewable energy can flow into and out of New England. This is where Vermont could provide an even more valuable contributing role to decarbonizing New England's economy. In VELCO's view, Vermont's transmission system will likely host a tie line expansion project that will enable the delivery of new renewable energy. This long-range Plan analysis, however, did not include any tie-line expansion project due to insufficient project specifics.

4.5.2 Generation

All Vermont generators that participate in the competitive wholesale markets are modeled in service unless a basis exists to model them out of service. Vermont generators are small, and the vast majority of them are not baseload generators expected to run at or near full capacity nearly every day for hours at a time. The largest single metered dispatchable Vermont generator is Kingdom Community Wind, a 65 MW wind plant that is characterized as an intermittent resource since its output varies as wind speed varies. The next largest generator is a 50 MW wood-burning plant, McNeil Generating Station, whose operation approaches that of a baseload generator. Other Vermont baseload plants are rated 20 MW or less and total approximately 30 MW.

ISO-NE recently developed a new process for determining the amount of generation that should be assumed out of service prior to testing outage events. The new process is simpler to model and more transparent. Consistent with Section 4.1.2 of the ISO-NE Transmission Planning Technical Guide, there are eight dispatchable thermal units in the Vermont study area, which allows two units to be placed out of service per dispatch. An additional unit that is greater than 50 years of age is modeled out of service, which results in a pre-contingency generation outage of the McNeil, Berlin, and Ascutney units, as referenced in Dispatches D1 and D4 on page 20 of the ISO-NE Needs Assessment study scope.[12] All other dispatchable thermal units were modeled at their maximum output.

VELCO believes that this generation outage assumption is optimistic considering the characteristics of the Vermont thermal generation portfolio. Since the previous long-range Plan, three thermal units have retired, and we anticipate that other thermal units will retire considering that nearly all of Vermont's thermal units are more than fifty years old. The amount of in-service thermal generation in this study is 20 MW greater than in the previous study, i.e., about the size of one of the two gas-fired turbines that comprise VPPSA's Project 10 in Swanton or the BED oil-fired turbine.

Based on historical performance, some units will be unavailable to run, fail to start, or trip shortly after starting. Additionally, the peaking resources are not designed to run for many hours. For instance, if the outage of concern is a long-duration outage such as a transformer failure, the peaking resources may be able to support the system for a handful of hours on the first day. However, when these resources are called upon the next day or the next few days after the outage because the load continues to be near peak levels, they may not be able to run, consistent with their run time before failure statistics.

4.5.2.1 The Highgate Converter

The Highgate Converter is the point at which energy flows between Hydro-Québec to Vermont's electric grid. The converter can carry the full amount of power contracted between HQ and Vermont distribution utilities during all hours of the year except periods of high demand that can affect the HQ system or periods of disadvantageous market conditions. Although the converter can operate at its full 225 MW capacity,[13] the converter currently operates slightly below this amount because the current 225 MW contract is located at the US border not at the converter. In addition, starting in the 2022/23 winter period, we have started to observe a more variable operation mode of the converter. The converter has exported energy to Québec during the last winter peak period, and it has operated at its full capability for 4000 hours in 2023 compared to the typical 8000 hours (out of 8,760) in previous years.

[12] https://www.iso-ne.com/static-assets/documents/2023/07/2023_07_13_pac_final_vt_2033_na_sow.pdf

[13] Accounting for losses, a slightly higher import amount, say 227 MW, would need to cross the US border to achieve 225 MW at the converter without undue negative system effects on the HQ and Vermont systems.

FIGURE 2 – COMPARISON OF HIGHGATE MW IMPORTS

As described above, transmission planners begin testing the system by assuming certain resources are already out of service, simulating conditions that are not unusual in system operation. Although Highgate is a significant resource supplying Vermont load, Highgate is not included in the ISO-NE calculation of the maximum allowable generation outage. Highgate is treated as a transmission facility, and its outage is tested as such. The increased variability at Highgate puts additional strain on the equipment, which increases the likelihood of a long-term failure. This was not modeled in this study, however, based on the recommendation of Vermont stakeholders regarding system design assumptions for the Vermont electric grid. As noted earlier in section 4.4.1, VELCO plans to review the condition of the 40-year old converter, and the results of this review may indicate a need to replace the converter.

4.5.2.2 Hydro and wind generation

Consistent with ISO-NE study methodology, hydro generation was modeled at 10% of audited capacity, and wind generation was modeled at 5% of nameplate capacity to represent expected summer conditions. The corresponding values for winter conditions were 25% for both hydro and wind generation.

4.5.2.3 Small-scale renewable generation

State policy, grant funding, federal tax incentives, favorable land prices and robust organizing and advocacy have greatly increased the amount of small-scale generation on Vermont's distribution system. The legislature adopted proposals in 2012 and 2014 that further expanded state incentives for small-scale renewables. Two programs—net-metering[14] and the standard offer program[15]—are assuring a market for the output of small-scale renewables. Net-metering rules that became effective on July 1, 2017,[16] eliminated any annual cap on net metering expansion, and provide positive and negative adjusters to the price paid for excess generation depending on siting and the ownership of renewable energy credits. As of April 2024, over 350 MW of net-metering nameplate capacity has been installed.

In 2013, the PUC modified the standard offer program to establish an annual solicitation at a pace dictated by statute, gradually increasing from the initial 50 MW amount to 127.5 MW. As of November 2023, approximately 85 MW of standard offer resources were in service, 87% of which were solar photovoltaic (PV) generation. Since January 2014, new standard offer installations include 0.04 MW of farm methane, 0.08 MW of wind, 3.2 MW of hydro, and 56 MW of solar PV accounting for 94% of the total amount added since 2014. In this analysis, it was assumed that all future standard offer projects would be solar PV.

In Vermont, net-metering and standard offer projects fall in the category of behind-the-meter (BTM) resources that reduce load from an ISO-NE perspective, do not participate in the ISO-NE markets and are not modeled as generators for transmission planning purposes in the same way as a market-registered asset. However, ISO-NE uses a modeling approach that takes these resources into account in planning studies. Those units that are sized 1 MW or less are represented as negative loads at each distribution substation based on a substation load-ratio share. Those units that are greater than 1 MW but less than 5 MW are represented individually as negative loads. ISO-NE assumes that solar PV generators will contribute approximately 26% of their installed capacity at the summer peak hour because of the timing of the New England-wide summer peak hour. This is modeled by reducing all solar PV units to 26% of their stated nameplate capacity. Recently, ISO-NE has begun to recognize the timing effect of solar PV in its studies. ISO-NE models solar PV at 90% of capacity in daytime minimum cases, 65% in summer daytime peak cases with high renewable output, 40% in summer daytime peak cases with low renewable output, and 0% in summer and winter evening peak cases. Since solar PV effects have shifted the Vermont summer demand peak to after sundown and winter peaks occur after dark, this analysis assumed that incremental solar PV would contribute 0 MW at the summer peak and winter peak hours.

In 2015 the Vermont legislature enacted a Renewable Energy Standard (RES) and energy transformation (ET) requirement.[17] The highlights are as follows:

- Total renewable requirement (55% by 2017 increasing to 75% in 2032), known as Tier 1—includes any vintage and large hydro from any source;
- New distributed generation carve-out (1% of sales in 2017 increasing to 10% in 2032), known as Tier 2; and,

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[14] Net-metering is an electricity policy for consumers who own small sources of power, such as wind or solar. Net metering gives the consumer credit for some or all of the electricity they generate through the use of a meter that can record flow in both directions. The program is established under Section 8010 of title 30.

[15] For more information about the standard offer program, see http://www.vermontstandardoffer.com/.

[16] Rules are available on the PUC's website at https://puc.vermont.gov/document/commission-rule-5100-rule-pertaining-construction-and-operation-net-metering-systems.

[17] Enacted as Act 56 of the 2015 Vermont General Assembly, codified in Title 30 Sections 8002-8005 of the Vermont Statutes Annotated.

- Energy Transformation Projects (2% of sales in 2017 increasing to 12% in 2032), known as Tier 3— projects that reduce fossil fuel use, which may be achieved through electrification of the thermal and transportation sectors through measures such as cold climate heat pumps, weatherization, and electric vehicles.

At the writing of this Plan, Vermont bill H.289 is under consideration, proposing mandates for both larger and smaller utilities to transition to 100% renewable electricity by 2030 and 2035, respectively. The Tier 2 requirements would increase to 20% by 2032 and 2035 for larger and smaller utilities, respectively. The Tier 3 requirements would increase to 12% and 10.667% by 2032 for larger and smaller utilities, respectively. A Tier 4 provision has been introduced, specifying new renewable energy requirements that will increase from 4% to 20% within a designated timeframe, varying based on the size of the utility.

All of the above programs contribute to Vermont's efforts to meet the renewable energy goals set in the 2022 Vermont Comprehensive Energy Plan (CEP), which builds on and re-establishes the 90% renewable energy by 2050 goal from the 2011 and 2016 CEPs, plus end-use sector goals of:

- Meet 25% of the remaining energy need from renewable sources by 2025, 40% by 2035, and 90% by 2050. Does not include the per-capita consumption goal explicitly.
- In the transportation sector, meet 10% of energy needs from renewable energy by 2025, and 45% by 2040.
- In the thermal sector, meet 30% of energy needs from renewable energy by 2025, and 70% by 2042.
- In the electric sector, meet 100% of energy needs from carbon-free resources by 2032 with at least 75% from renewable energy.

These renewable energy goals serve as important considerations for the 2024 Vermont Long-Range Transmission Plan and informed our Vermont Roadmap load forecast scenario. Although, the proposed RES modifications were not explicitly modeled due to timing. The DG hosting portion of the Plan analysis modeled a simplified Tier 2 increase from 10% to 20% by 2032 assuming all of this increase would be achieved with solar PV at a 14% capacity factor. A 100 MW solar PV generator with a 14% capacity factor is equivalent to a 14 MW generator running at full output for 8760 hours.

4.5.2.4 Proposed generation projects in the ISO-NE interconnection queue

The analysis takes into account any new generators that have a capacity supply obligation. No proposed queued projects were modeled. Historically, many proposed generation projects ultimately withdraw their interconnection requests due to financial difficulties, permitting, local opposition, inability to find customers and other factors. Since 2018, thirteen projects have requested interconnection, including three battery storage projects. Ten of these projects, including all storage projects, have withdrawn from the queue.

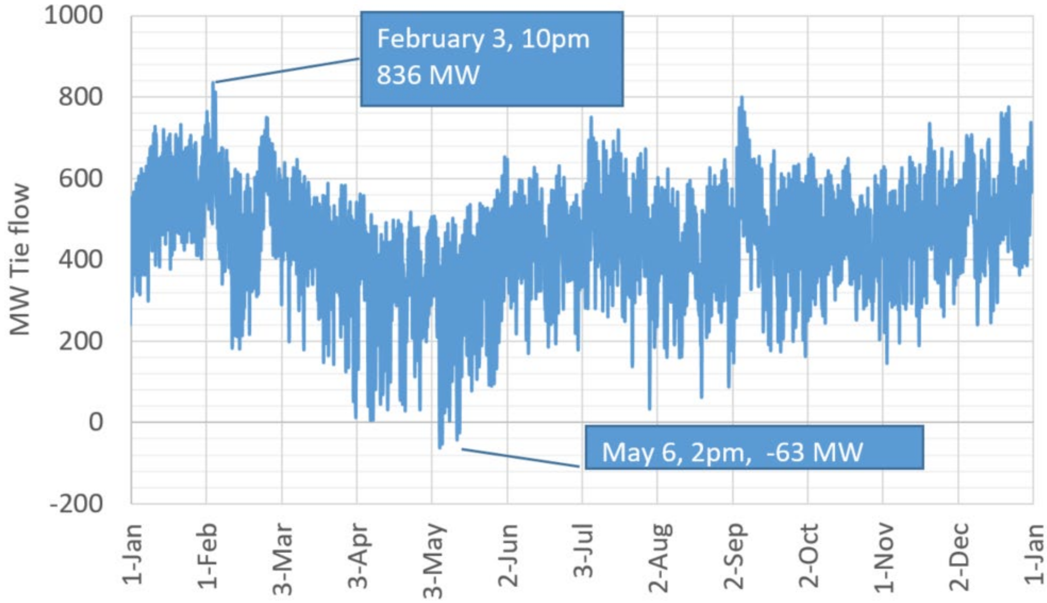
4.5.2.5 Vermont as a net importer

Vermont has roughly 1100 MW of installed generation, including approximately 500 MW of distributed solar PV and 87 MW of other small-scale generation that includes 56 MW of storage. This amount of generation exceeds recent seasonal peak load levels. Due to the performance characteristics of in-state generation, however, Vermont has relied heavily on its transmission network to import power from neighboring states. Following the shutdown of the Vermont Yankee generation plant in 2014, Vermont has become a net importer of power at nearly all hours from New York, New Hampshire, Massachusetts, and Canada in order to meet the state's load requirements. Because of the disproportionate reliance on solar PV generation, high imports during peak load conditions will continue over the long term. Below is a table showing import statistics since 2015.

TABLE 4 – HISTORICAL VERMONT MW IMPORT STATISTICS

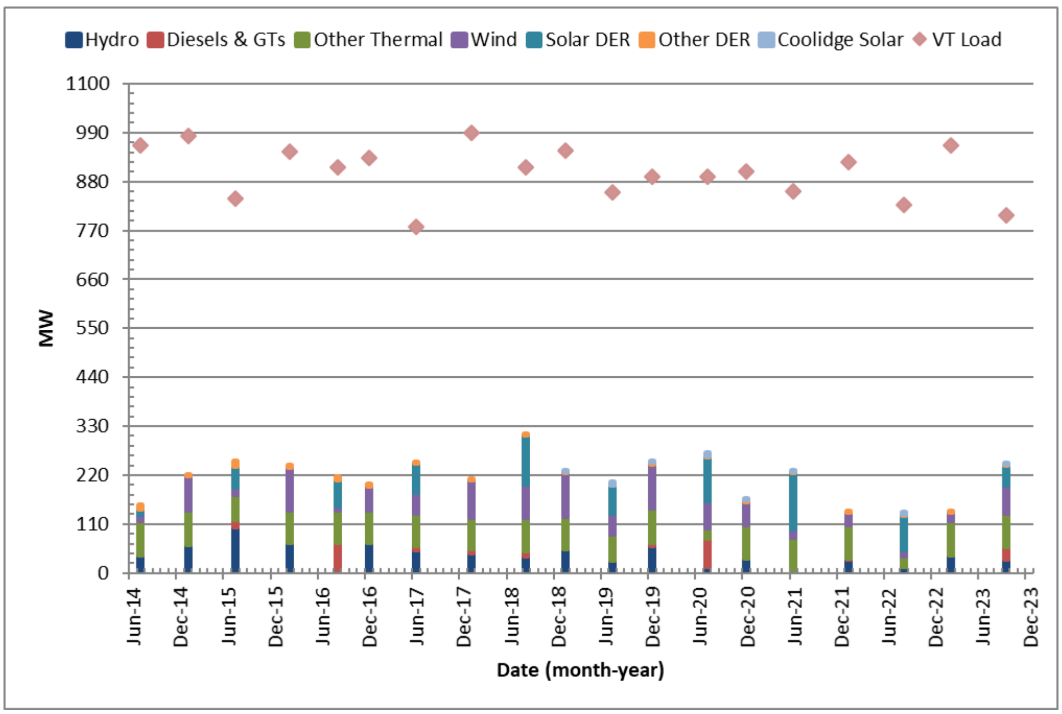
Year	Minimum	Maximum	Percent of time over 400 MW
2015	198	910	84%
2016	223	842	86%
2017	234	810	80%
2018	139	833	80%
2019	100	850	70%
2020	14	856	69%
2021	30	854	73%
2022	20	861	71%
2023	-63	836	64%

FIGURE 3 – VERMONT MW IMPORTS IN 2023



The following graph shows the contribution of internal resources serving Vermont load during the New England peak hour.

FIGURE 4 – VERMONT GENERATION DURING THE NEW ENGLAND PEAK HOUR



While energy efficiency is not explicitly plotted it is a resource that ISO-NE has acquired to reduce electrical demand during peak-load periods. Energy efficiency, demand response, and distributed energy resources (DERs) mainly reduce the demand at the distribution level. DERs typically include standard offer, net-metering, and utility-installed resources that are currently treated as behind-the-meter resources. As shown in the above graph, the contribution of solar PV at the ISO-NE peak hour is dropping because the timing of the New England summer peak has moved to 6PM. For example, the solar PV output was about 50 MW during the New England 2023 summer peak, i.e. roughly 10% of the installed solar PV capacity. As solar PV increases in New England the ISO-NE summer peak timing will continue to move later in the evening, and solar PV contribution will be gradually reduced to 0 MW. As will be discussed in section 4.5.4 on page 38, the contribution of solar PV resources is already nearly 0 MW at the Vermont peak hour because solar PV has moved the Vermont peak hour to after sundown. Historical data from the past few summer and winter peak hours indicate that the transmission system serves anywhere from 75% to 90% of the peak load depending on the production of intermittent generation resources at the Vermont non-coincident peak.

4.5.3 Forecasting demand

Each of the sixteen planning load zones was forecast individually, and then combined to calculate the statewide load. This approach was used to avoid the possible distortion of some of the zonal load shapes. Our load forecast consultant, Itron, with the assistance of the Vermont System Planning Committee and the Vermont Efficiency Investment Corporation (VEIC), produced the *Continued Growth* and *VT Roadmap* load forecast scenarios instead of the low, medium, and high scenarios produced for the 2021 Plan. The cold climate heat pump (CCHP) forecast uses the same medium adoption rate as in 2021. The VT Roadmap electric vehicle (EV) forecast uses the high EV adoption rate instead of the medium adoption rate. The EV forecast also includes a fleet EV forecast based on the ISO-NE fleet EV forecast, but extended to 2043 since the ISO-NE 2022 EV forecast stopped in 2032. Further, this forecast assumes that 20% of residential EVs will charge during the day at the workplace or at public charging stations, which will reduce the charging load during daily peak periods. The Plan analysis does not model EV charging load management as in the previous Plan where we assumed that 75% of EV charging load would be managed. This uncontrolled load approach allows us to determine when, where and how much load management would be required.

4.5.3.1 Load forecast process

The analysis models future electric demand consistent with the results of a load forecast completed in June 2023 by Itron, an energy firm that offers highly specialized expertise in load forecasting, under contract by VELCO. Planning studies for this long-range Plan assume peak load conditions that occur during severe weather conditions. This is also called a “90/10 forecast”, meaning there is a 10% chance that the actual load will exceed the forecast. This long-range Plan analyzed summer and winter peak loads, as well as a lower load level, net of solar PV generation, that the transmission system would serve on a normal sunny day in spring.

The forecast of future demand for electricity is a critical input in electric system planning. The forecast determines where and when system upgrades may be needed due to inadequate capacity. Predicting future demand relies on assumptions about economic growth, technology, regulation, weather, and many other factors. In addition, forecasting demand requires projecting the demand-reducing effects of investments in energy efficiency and small-scale renewable energy. The following section summarizes the forecast underlying this Plan. More detailed information about the forecast can be viewed on the VSPC website.[18]

In developing the Vermont forecast, Itron incorporated the latest energy efficiency projection in collaboration with the Vermont Department of Public Service (DPS), VEIC, and the VSPC. Itron employs an end-use model that essentially forecasts each consumption type—e.g., lighting, heating, and cooling—that contributes to the overall load forecast. Regression analyses of twenty years of historical data are then performed to capture economic growth effects, weather (including long-term impacts due to climate change), and other factors affecting energy consumption and peak demand.

4.5.3.2 Load forecast scenarios

To address uncertainties in load forecasts, planners prepare both a high and a low forecast to encapsulate the range of potential outcomes. In this case, the high forecast is also the VT Roadmap load forecast since it represents the effects of Vermont policies. Both the high and low forecasts were tested, and the results of these studies allowed us to determine the timing of system concerns.

The *VT Roadmap* EV forecast scenario models EVs making up a 90% share of non-fleet light duty vehicles by 2040. In the *VT Roadmap* case, the number of EVs increases to nearly 300,000 electric vehicles by 2033 and 420,000 by 2040. In the *Continued Growth* case, we assume a slower adoption rate (VEIC's medium EV projection) as a result of slower infrastructure buildout; in that scenario, the EV saturation rate is close to 60% by 2043, representing 272,000 electric vehicles. The fleet electric vehicle forecast is based on ISO-NE's Draft 2023 Transportation Electrification Forecast for Vermont. The ISO-NE forecast provides vehicle count forecasts and average kWh per day for light-duty fleet, medium-duty fleet, school bus, and transit bus vehicle types through 2032. The long-range Plan forecast extended the ISO-NE fleet vehicle forecast to 2043. The energy forecast is affected mostly by the non-fleet vehicles whose combined energy consumption is four to five times greater than the fleet vehicle energy consumption.

For the *VT Roadmap* heat pump forecast, we show that 50% of the homes in the state will have heat pump heating and cooling systems by 2043. The cumulative number of heat pump units is expected to increase to about 280,000 units by 2043. In the *Continued Growth* case, we assume heat pumps are installed at the current rate of 10,500 units through 2034 and then track the declining adoption path after that due to increasing saturation and expected replacements of units reaching their end of life. The number of units is translated to energy consumption based on unit energy estimates derived from an earlier Cadmus study for Vermont. The energy consumption in the *VT Roadmap* heat pump energy forecast is projected to be 30% higher than in the *Continued Growth* heat pump energy forecast.

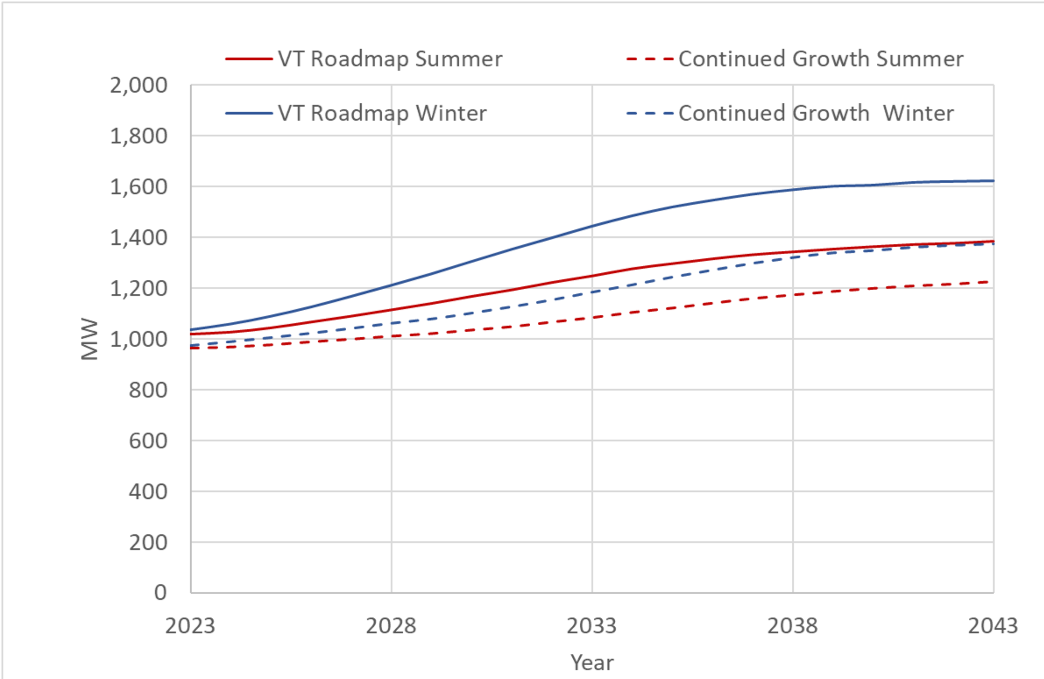
In choosing the *VT Roadmap* forecast for electric vehicles and heat pumps, we focused on the high forecast because Vermont law requires significant greenhouse gas emissions reductions by specific dates. The Vermont Legislature has enacted Act 153, the Vermont Global Warming Solutions Act of 2020. Section 3 of the Act amends 10 V.S.A. § 578 to require reductions in statewide greenhouse gas emissions in three stages:

- By January 1, 2025: not less than 26% below 2005 emissions;
- By January 1, 2030: not less than 40% below 1990 emissions; and

[18] https://www.vermontspc.com/sites/default/files/2024-01/VELCO_FcstCommittee_June_2023.pdf

- By January 1, 2050: not less than 80% below 1990 emissions.

FIGURE 5 – LOAD FORECAST SCENARIO COMPARISON



The summer *VT Roadmap* load forecast (solid red line) is higher than the *Continued Growth* load forecast (dashed red line) by 60 MW in 2024, 104 MW in 2028, 165 MW in 2033, and 160 MW in 2043. The winter *VT Roadmap* load forecast (solid blue line) is higher than the low-load forecast (dashed blue line) by 69 MW in 2024, 150 MW in 2028, 261 MW in 2033, and 260 MW in 2043. The *Continued Growth* load forecast scenario delays the timing of the peak load levels. For example, the 1116 MW summer peak load that is projected to occur in 2028 would not occur until seven years later in the *Continued Growth* load scenario, and the 1212 MW winter peak load that is projected to occur in 2028 would not occur until six years later in the *Continued Growth* load scenario. While significant load growth is anticipated, there remains uncertainty around the magnitude and the timing as discussed above and in section 4.5.5. These forecasts are based on the best-known information at this time. As more current information becomes available, these forecasts will be updated. At a minimum, a new set of forecasts will be prepared as part of the 2027 long-range Plan and every three years thereafter.

The following graphs depict the twenty-year severe weather, or 90/10, forecast adjusted for the effects of energy efficiency, the standard offer and net-metering programs, and future load increases due to heat pumps and electric vehicles. The load forecast reflects long-term weather effects that do not vary significantly from year to year, and the forecast curve is smoother than actual peaks, which vary from year to year depending on weather conditions. The base load forecast (grey line) has been adjusted for energy efficiency programs. The total load forecast (red line), net of solar PV, is the sum of the base forecast and the component forecasts that would either increase or decrease the load depending on the technology. The graphs show the component forecasts representing the projected impact of: electric vehicles (EV, dotted green line); heat pumps (HP, dotted orange line); and, solar PV (dotted yellow line), which is 0 MW because the seasonal peaks occur after dark.

FIGURE 6 – PROJECTED VERMONT SUMMER PEAK LOAD AND ITS COMPONENT FORECASTS

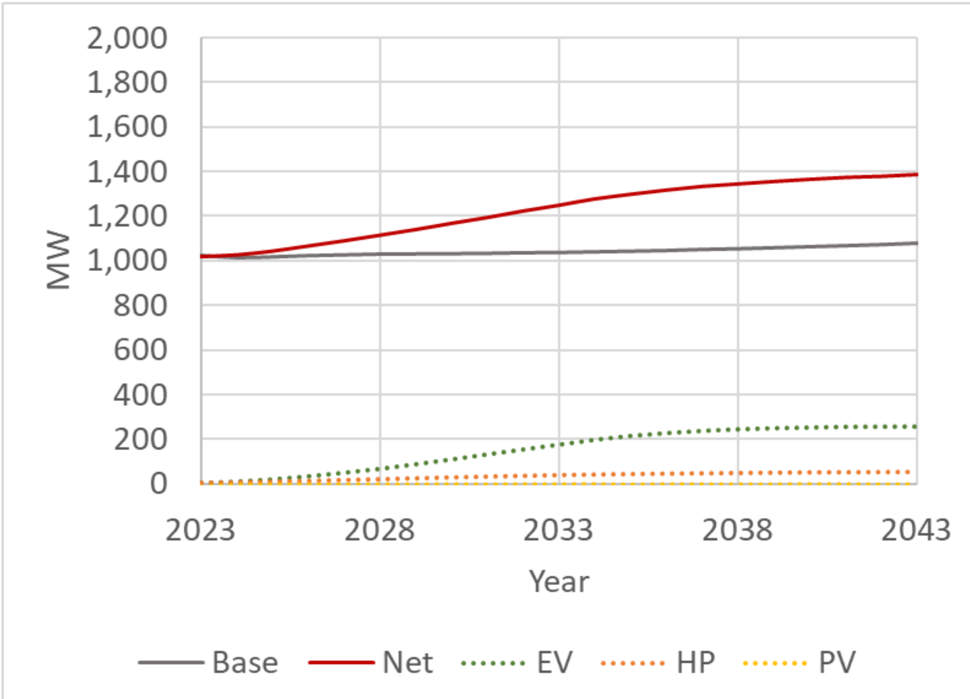
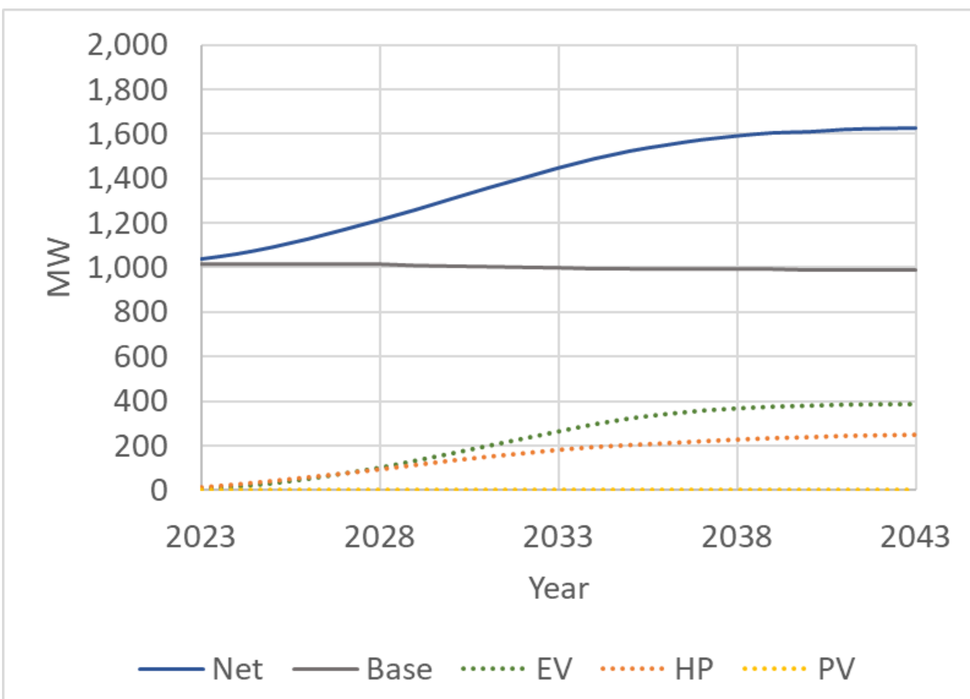


FIGURE 7 – PROJECTED VERMONT WINTER PEAK LOAD AND ITS COMPONENT FORECASTS



While the base forecast is relatively flat, the net forecast predicts sustained load growth mainly driven by the growth of electric vehicles and cold climate heat pumps. Even so, the summer peak is not predicted to reach the previous all-time peak of 1120 MW until 2028. The winter peak grows faster than the summer peak and is projected to reach the previous all-time winter peak of 1086 MW in 2025. The load forecast projects total summer peak load levels in 2024, 2033, and 2043 of 1028 MW, 1250 MW, and 1386 MW, respectively. The corresponding total winter peak load levels are 1056 MW, 1445 MW, and 1624 MW, respectively.

4.5.3.3 Electric vehicle forecast

The demand associated with EVs is predicted to become a noticeable component of the peak load in the mid- to long-term. The electric vehicle forecast, developed by VEIC, provided the number of electric vehicles and associated energy consumption. As of December 2023, there were 12,710 passenger EVs registered in Vermont, which is nearly 8,350 more EVs than in 2020. Presently, EV adoption rates are not growing as fast as would be necessary to meet Vermont's climate goals. VEIC produced three EV adoption rates: low, medium, and high. The VEIC EV forecast is based on the percentage of total registered vehicles and the application of the Advanced Clean Cars II rule applies to new vehicle sales. Under the VEIC high case saturation level, 100% of new vehicles sales would have to be electric by 2025.

The *VT Roadmap* EV forecast predicts that the EV electrical demand at the summer peak hour will grow from 9 MW in 2024, to 66 MW in 2028, 175 MW in 2033, 243 MW in 2038 and 256 MW in 2043. The winter EV demand is expected to be somewhat higher based on historical EV demand. The corresponding winter peak demand figures are 14 MW in 2024, to 100 MW in 2028, 262 MW in 2033, 366 MW in 2038, and 384 MW in 2043. These figures assume no load management because it enables system concerns to be properly identified, which then allows us, in turn, to quantify the needed load management measures. Since the utilities already have programs in place to manage load, the existing amount will reduce the total load control need described in this Plan.

4.5.3.4 Heat pump forecast

High-efficiency heat pumps, also called cold-climate heat pumps, can provide heating at temperatures below 0°F at greater efficiency than several other heating sources. Heat pump capabilities decrease as temperatures approach -15°F, but the technology is evolving, and it is no longer uncommon to see products that can operate at temperatures as low as -22°F and even -30°F.

State incentives have been very effective at encouraging heat pump adoption. Roughly 50,000 heat pumps have been installed over the last five years, and the VEIC expected-case forecast predicts annual net sales to increase to 18,000 units by 2030. The *VT Roadmap* heat pump forecast shows the HP electrical demand at the winter peak hour will grow from 27 MW in 2024, to 94 MW in 2028, 183 MW in 2033, 229 MW in 2038, and 250 MW in 2043.

The ability to cool with the same high-efficiency equipment will increase the existing cooling load. The summer HP demand figures grow from 6 MW in 2024, to 20 MW in 2028, 38 MW in 2033, 47 MW in 2038, and 52 MW in 2043. These winter and summer HP forecasts assume no load management because it enables system concerns to be properly identified which then, in turn, allows us to quantify the needed load management measures.

4.5.3.5 Net-metering forecast and incorporation of standard offer solar PV

Starting in 2012, net-metering and standard offer installed capacity have increased rapidly, driven by Vermont policies encouraging renewable energy development to the point of changing the behavior of the daily system load. As a result of these policies, Vermont has seen a significant increase in solar PV generation, the predominant technology since 2012, with lesser contributions from wind, hydro, biomass, and methane. Itron used a payback model to forecast net-metering solar PV. The model indicated fairly aggressive growth in the near term followed by a slow down due to projected slower declines in equipment costs. The forecast projects net-metering solar PV to grow to 538 MW in 2028, 561 MW in 2033, 580 MW in 2038, and 588 MW in 2043.

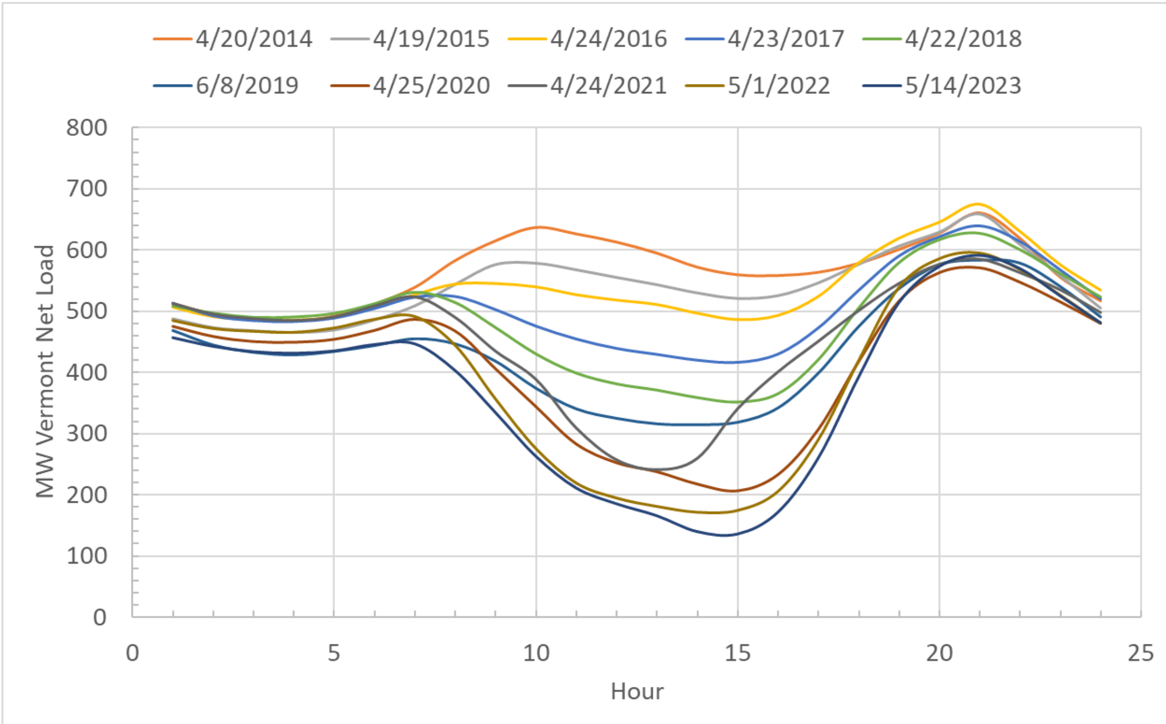
Standard offer is fully subscribed with 128.6 MW under contract, and 82 MW already in service. Of this installed amount, 74 MW is solar PV, and 39 MW of solar PV are planned. Additionally, 3 MW of farm methane generation has been installed but is outside the program cap. Currently, there are no plans to prolong the standard offer program, and the maximum amount was held constant going forward.

The Itron load forecast indicated that the summer and winter peak net load will occur after dark. Therefore, the contribution of solar PV at the peak hour is predicted to be 0 MW, which means that the peak load is not reduced by the amount of projected amount of installed solar PV.

4.5.3.6 High solar PV forecast scenario

Solar PV has grown to nearly 500 MW as of December 2023. The rapid growth in solar PV has had a significant impact on midday loads, particularly during spring when the load is typically lower due to cooler temperatures and higher solar PV production. Historical data show that the midday load has become lower than the nighttime load starting in 2017. The following graph shows how the lowest observed midday loads have progressively dropped over the past few years. It is anticipated that Vermont’s total net load will become negative during the lighter load periods within five years.

FIGURE 8 – SOLAR PV IMPACT ON VERMONT NET LOADS

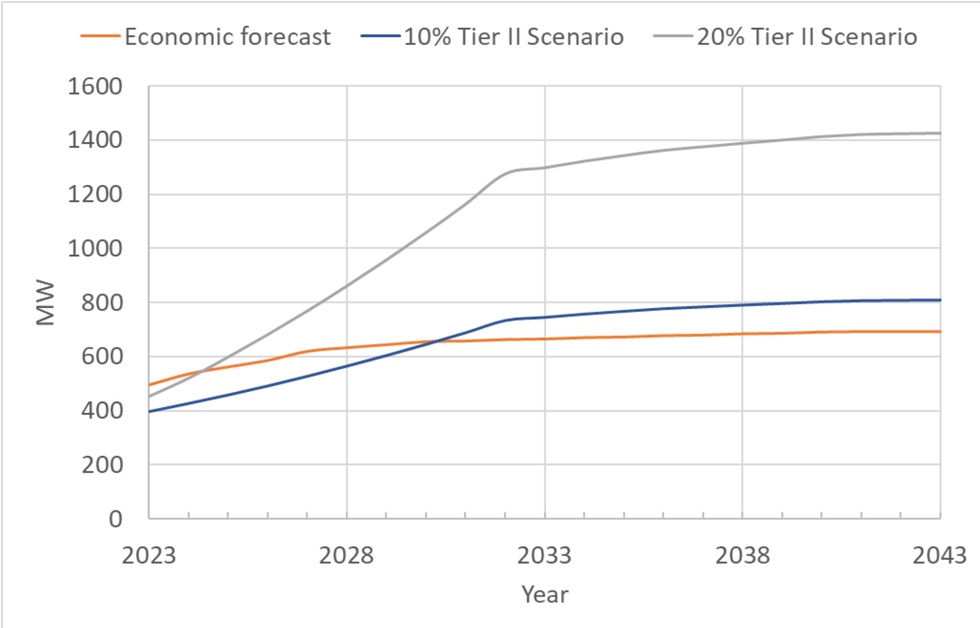


On a more local level, solar PV has started to reverse power flows through VELCO transformers serving distribution utilities. Flow reversal is not necessarily a reliability concern, but one could envision transformers and other substation equipment overloading eventually as solar PV continues to grow. VELCO and ISO-NE are not directly involved in studies of small-scale, distribution-connected generation. VELCO monitors transformer and transmission line flows to identify changing or emerging patterns. ISO-NE planning procedures require that appropriate studies be conducted when the aggregate level of new distributed generation is sufficiently large to require more detailed studies that would demonstrate no significant adverse impacts on the transmission system. When the ISO-NE generation saturation threshold is reached for a single substation or a cluster of substations, the small-scale generators need to be modeled explicitly as generators as opposed to negative loads, and studies need to be conducted with the same rigor as generators proposing to connect to the transmission system. Vermont distribution utilities have noted that they are able to minimize the likelihood of reaching the ISO-NE saturation thresholds by limiting the amount of DG to the size of their distribution substation transformers. The cluster studies require detailed models that adequately represent the dynamic behavior of generators in response to system disturbances. These studies are managed by the local system operator and coordinated with affected system operators and ISO-NE. In Vermont, this coordination process is expected to be more complicated than elsewhere because the distribution utilities and VELCO are separate entities, and the distribution utilities are not as experienced with transmission level studies. In addition, distribution utilities may not have an established process for managing transmission studies. The utilities will need to develop procedures addressing which units should be in the cluster, which existing and new units need to provide detailed models, what are the penalties for leaving the study or modifying the project in a material way, how the study cost is allocated, and how system upgrade costs are allocated. As noted earlier in the Plan, the cluster study requirement applies to DG greater than 1 MW but less than 5 MW, but not to DG 1 MW or less. Proposed DG projects in the cluster would not go forward until studies are completed and upgrades are implemented. After the completion of a cluster study, a single additional DG in the cluster area will require a transmission level study for DG greater than 1 MW but less than 5 MW.

In areas where hydro and wind generation is high compared to native load, curtailment of these generators may be necessary to prevent system concerns on a real-time basis. Such curtailment may be undesirable and should be minimized. For instance, some of the generators subject to curtailment are owned by or under contract with Vermont distribution utilities. When these generators are curtailed, revenues are potentially reduced, which negatively affects the financial performance of the generators and increases the utility's costs, which may result in higher customer electric rates.

Itron did not develop a high solar PV scenario, but we estimated the effects of doubling the Tier II requirements of the RES to 20%. As noted previously, Itron provided a forecast that is incremental to the small-scale solar PV installed as of 2022. The Itron forecast uses an economic payback model, which predicts investments based on the customer's perceived economics. A shorter payback period would spur more investment. The Itron economic payback forecast is shown in orange in the following graph. The economic forecast rises quickly to roughly 634 MW in 2028, and remains above the current 10% Tier II requirement (blue curve) until 2030. The 10% Tier II obligation was calculated to be 733 MW in 2032, and it continued to increase because the energy forecast increases. If the Tier II requirement is simply doubled to 20%, the Itron *VT Roadmap* PV forecast is exceeded as early as 2025. The 20% Tier II scenario would reach 1275 MW in 2032 assuming the requirement is meant by solar PV with a 14% capacity factor. All solar PV amounts discussed in this Plan refer to nameplate capacity. Future solar PV is modeled based on the present-day geographical distribution. Analysis was conducted to determine the transmission system's ability to accommodate a large amount of solar PV, and that analysis resulted in an optimized geographical distribution of solar PV that would avoid or minimize system concerns. While very useful, VELCO does not view an optimized PV geographical distribution as likely.

FIGURE 9 – SOLAR PV SCENARIOS



4.5.3.7 Load management

The loads modeled in the analysis do not reflect any load control in order to identify the location and severity of system concerns and determine whether these concerns are related to load growth, in which case the amount and location of load reduction will be estimated. Load management can be achieved with several technologies and approaches that are appropriate to resolve the reliability concerns.

Vermont distribution utilities, in partnership with the statewide energy efficiency provider, Efficiency Vermont, have initiated pilot projects or have collaborated with innovative Vermont-based companies to manage load. A non-exhaustive list of these efforts include installing batteries at customers' premises for continued service during outages and load management at other times, remote control of water heaters, heat pumps, electric vehicle chargers, and HVAC. Currently, several tens of megawatts can be controlled. We expect this number to grow significantly as adoption of electric vehicles and heat pumps continues to grow and the technology facilitating load management continues to evolve. There have been frequent discussions about flexible load management as a separate class of load control. We think that flexible piece of load management is a reflection of the load's characteristics, meaning the extent to which the load can be moved in time, and the type of control technologies would enable. Therefore, flexible load management is not listed as a separate category below. Load control can include and is not limited to:

Demand response in the ISO-NE forward capacity market (FCM) varies based on market forces and can easily leave the market at any time. Demand response is also called price-responsive demand because it can be offered in the energy and reserve markets based on real-time prices. Because of this real-time market aspect, data is not available to VELCO to understand demand response performance that would allow VELCO to model demand response correctly. Further, location matters when deploying demand response to address system concerns. Without locational data, it can be overly optimistic to model demand response across the entire state, and thus demand response was not modeled in this analysis. The amount of demand response that could have been modeled based on the ISO-NE FCM data is about 30 MW based on the last six auction results. In the last 13 years, demand response has been as high as 50 MW and as low as 25 MW.

Rate design and active load control have been used by Vermont distribution utilities to incentivize their customers to consume energy at certain times and to not consume at other times. Part of this program includes active load control where customers are given discounts, payments, or share in savings for allowing the utility to control their consumption. Any appliance can be controlled so long as it is outfitted with the appropriate technology. Rates can be designed to take advantage of load flexibility where the consumption is moved in time. For example, a house could be preheated a few degrees over the normally desired level, and then the thermostat setting could be reduced below the normal level to avoid heating load during the daily peak load period, to later increase the setting to the normal level after the peak period. Electric vehicles, water heaters, heat pumps, and other similar loads are suitable for being utility controlled.

Storage is often the proposed solution for all system ailments irrespective of its cost, energy limitations, relatively short life span, and the complexity of storage operation. Thus far, distribution utilities have used storage primarily to manage peak loads. Storage also participates in the markets, e.g., to provide frequency regulation and energy services. An example of the operational complexity is a storage device that is in the frequency regulation market and is therefore precluded from being counted on for providing capacity benefits during a reliability deficiency event.

Microgrids are a form of load control, which can be done either by the microgrids taking load off the system after an outage or in anticipation of a system event to reduce its impact. Microgrids are small electric systems that are designed to be self-sufficient with generation resources, renewable or not, that can operate in an islanded mode, i.e., without being connected to the electric grid. Microgids can be off-grid all the time, or they can be made operational during an emergency event such as in a storm. The Vermont distribution utilities have such systems, but they are currently too small to provide sufficient benefits in response to a transmission event.

As noted earlier, the Plan notes the amount of load that needs to be reduced to ensure the transmission grid meets the federal and regional reliability performance standards. The manner in which the load is reduced will depend on the project sponsors, and load control measures will be acceptable as long as they are demonstrated to be able to reliably resolve the identified concern. First, VELCO will model and determine whether the proposed solution addresses the identified system concerns. Second, there needs to be sufficient certainty that the solution will perform adequately when called upon. This can be done in several ways as outlined in section 4.1(f) of Attachment K of the ISO-NE Open Access Transmission Tariff. One of the ways outlined is for the solution to be included in the load forecast, which can occur by participating in the markets or being excercised regularly, e.g. during each peak period, similar to an emergency generator.

4.5.4 Peak demand trends

The increasing adoption of small-scale renewable energy has been successful at reducing day-time load. The winter peak load has been relatively constant at roughly 1000 MW, while the summer peak load has decreased from 1040 MW in 2013 to below 950 MW. However, the annual peak can occur either in the summer or winter depending on which of these two seasons experiences more severe weather.

Small-scale renewable energy has also affected the timing of the peak during the summer months, June to September. Since 2014, the summer peak day timing has occurred after dark, and it is not rare for the peak to occur at 8pm or later. As noted earlier, while the load forecast predicts solar PV to grow over 700 MW in the long term, the contribution of solar PV generation during the summer or winter peak hour is 0 MW due to misalignment of solar PV production relative to the timing of the summer and winter peaks, which typically occur between December and February.

System planning analyses take the timing of the peak into account. The shape of the Vermont load curve on a summer peak day has traditionally been quite flat, but it is expected to change due to solar PV and electrification. Small-scale renewable generation is making the curve more concave in the middle of the day, and electrification is expected to make the nighttime peak hours more pronounced. This transformation is relevant to the development of non-transmission alternatives such as energy efficiency, generation, and the load control measures described above.

4.5.5 Uncertainties in the timing of need for reliability solutions

System analysis determines at what level of electric demand a reliability problem would occur, and load forecasting predicts when that load level would be reached by using mathematical methods to predict demand based on the expected influence of factors such as economic activity, price elasticity, population growth, new technology, efficiency, long-term weather trends, and public policy effects on customer behavior. The timing of load-level predictions is inherently uncertain due to the complexity and uncertainty of these factors. Although load forecasters use various methods to minimize uncertainties, the longer the horizon the more uncertain are the drivers of customer demand. The resulting load forecast and, consequently, the year in which reliability concerns will arise are impacted by the following factors.

- Itron's load forecast is based on known information, including input provided by the VSPC as part of the forecast process. Some substation loads may or may not be present in the future, and their status can affect system performance. For example, the winter peak load in the Newport load zone can be higher than the Itron forecast, depending on the amount of load at the Jay Peak Ski Resort and whether currently absent load from one industrial customer is reinstated. Similarly, a load increase at a manufacturer's facility can affect system performance in the St. Albans load zone. The status of that one customer's load can trigger the need for a system upgrade.
- Energy efficiency may be more difficult or expensive to obtain over the long run as easier and less costly load reductions have already been achieved. Because small-scale renewable energy is having an impact on the timing of the peak, energy efficiency measures that target specific load hours may become less effective if the portfolio of measures is not modified to match the later peak load timing, or the coincident factor of those measures may become less predictable due to the variability of peak load timing.
- New FERC and ISO-NE requirements for treating and paying demand response programs on par with generation introduce uncertainty regarding future participation rates and effectiveness of demand response for customers who will be called upon to curtail load based on the energy

market rather than system events and conditions as in the past. In 2020, FERC issued Order 2222 that allows distributed generation to be aggregated and participate in wholesale markets. Currently, VT distribution utilities are not required to comply with Order 2222 as they have less than 4M MWh of electric sales annually.

- New technology may increase or decrease electric demand in the long run. For instance, the batteries in electric vehicles may become a distributed energy resource through the use of smart grid technologies, or they may increase electric demand if they are charged during peak demand periods. The distribution utilities are designing rates to incentivize their customers to consume energy in a way that does not contribute to peak load. As transportation and heating are electrified, load management will become more critical and more challenging to design and implement. Therefore, it is difficult to predict and model load management, which affects the timing of system needs.
- Serving as an integral part of the interconnected grid, the Vermont system needs to be designed in coordination with Vermont neighboring states and with consideration of activities within and outside of New England. All states have some form of decarbonization goals, have programs in place, and have taken steps to meet these goals. Several thousands of megawatts of offshore wind generation may be developed along the New England and New York coastlines. ISO-NE studies have identified potential challenges in integrating offshore wind, and it has been suggested that significant storage will be needed. Storage could be in the form of batteries and other technologies, or it could involve exporting excess renewable energy to neighboring systems to later import a similar quantity of energy when needed. Vermont has several tie lines with New York and Canada, and we should consider reinforcing our ties to enable two-way renewable energy exchanges to facilitate renewable energy growth while maintaining energy and capacity adequacy. A number of developers are interested in constructing transmission projects in Vermont. Those projects may or may not go forward based on several factors, but they will only be truly successful if they improve the reliability and resilience of the Vermont system and bring sufficient value to Vermont customers.
- Renewable energy and small-scale distributed generation have expanded dramatically. There are discussions about doubling or tripling in-state, small-scale renewable generation, currently set at 10%. Regardless of the amount, it is unclear where generation will be developed and at what rate of growth. It is assumed that most of that generation will be solar PV that would result in an amount of total generation that could cause grid concerns. The ISO-NE interconnection procedures do not apply to generation sized 1 MW or less. Currently, two thirds of the small-scale generation fall in that category, and there are no mechanisms for ISO-NE or VELCO to assess the transmission system impacts except as part of ISONE needs assessments (the VT needs assessment was updated after ten years) or the long-range plan studies that are updated every three years. If a concern is identified, we are not aware of any way to address potential concerns except than to manage those generators that participate in the markets and manage load. So, we may be able to catch up to the system concerns, but there will likely be a delay, and it is not certain how these concerns would be addressed and who would fund the solutions.

- Reliability standards set by NERC continue to evolve in order to ensure the system remains reliable while it is transforming as a result of aggressive decarbonization policies, more frequent, severe, and disruptive weather events, cyber attacks, and other concerns as they arise. The following table lists the more transformational Orders and Notices issued by FERC in the last three years. For instance, FERC directed NERC as part of Docket No. RM22-10-000, Order No. 896, to develop a new or modified Reliability Standard to address reliability concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the Reliable Operation of the Bulk-Power System. FERC also directed NERC as part of Docket No. RM22-12-000, Order No. 901, to develop new or modified Reliability Standards that address reliability gaps related to inverter-based resources in the following areas: data sharing; model validation; planning and operational studies; and performance requirements. FERC's major orders over the past three years will change how VELCO plans and operates the transmission system. VELCO will be engaging stakeholders as these requirements become effective.

TABLE 5 – FERC MAJOR ORDERS OVER THE PAST THREE YEARS

Date	Title	Order No.	Docket
10/19/2023	Reliability Standards to Address Inverter-Based Resources	Order No. 901	RM22-12-000
7/27/2023	Improvements to Generator Interconnection Procedures and Agreements	Order No. 2023	RM22-14-000
6/15/2023	Transmission System Planning Performance Requirements for Extreme Weather	Order No. 896	RM22-10-000
4/21/2022	Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection	Notice of Proposed Rulemaking	RM21-17-000
2/17/2022	Implementation of Dynamic Line Ratings	Notice of Inquiry	AD22-5-000
12/16/2021	Managing Transmission Line Ratings	Order No. 881	RM20-16-000

- The best available information was used to determine the zonal distribution of technologies that affect loads. Solar PV is allocated to zones based on currently installed solar PV distribution; EVs are allocated based on the zonal share of registered EVs; and heat pumps are allocated based on zonal distribution of electric energy consumption. These methods, while appropriate, may not be an accurate depiction of future deployment. Alternative zonal distributions will affect system performance.
- Federal and state policies have a significant impact on loads. The Vermont Renewable Energy Standard and energy transformation requirements include provisions that both increase and decrease loads. Depending on how these requirements are met and managed, loads can be higher or lower than the load forecast. Further, it is impossible to predict the timing and the specific requirements of new policies. The Vermont Department of Public Service prepared a

comprehensive report on the deployment of storage on the Vermont grid[19] that may help guide future policymaking; however, Vermont may or may not establish storage requirements that affect grid performance. Storage was not modeled in the load forecast since it would be premature to do so without knowing what requirements may be imposed. That said, storage is virtually certain to be among the solutions considered to address emerging system concerns.

Some uncertainties can be quantified because they are known and well understood based on historical data. For example, we can determine the expected contribution of hydro generation to be roughly 10% at the time of the summer peak hour, the likelihood that a generator or type of generator will be unavailable, or the probability that the summer peak load forecast will be exceeded. Other uncertainties are unknown, such as generation expansion, natural disasters or terrorist attacks, and public policies whose timing, specific requirements and corresponding impacts on future loads can have a significant impact on system performance. Planning under conditions of uncertainty involves making decisions that minimize or hedge against risks, and several approaches are used, including what-if analyses and minimax regret optimization.[20] Faced with significant unknowns, two peak demand scenarios and two solar PV scenarios were developed to represent possible energy futures—recognizing that they are not necessarily the only possible futures—in an effort to understand these impacts and wisely guide investment decisions that will support Vermont's overall goals and maintain electric system reliability.

[19] http://publicservice.vermont.gov/sites/dps/files/documents/Pubs_plans_Reports/Energy_Storage_Report/Storage_Report_Final.pdf

[20] Minimax optimization is an algorithmic process used to minimize the worst-case potential loss. Regret in this case is an opportunity cost from making the wrong decision.

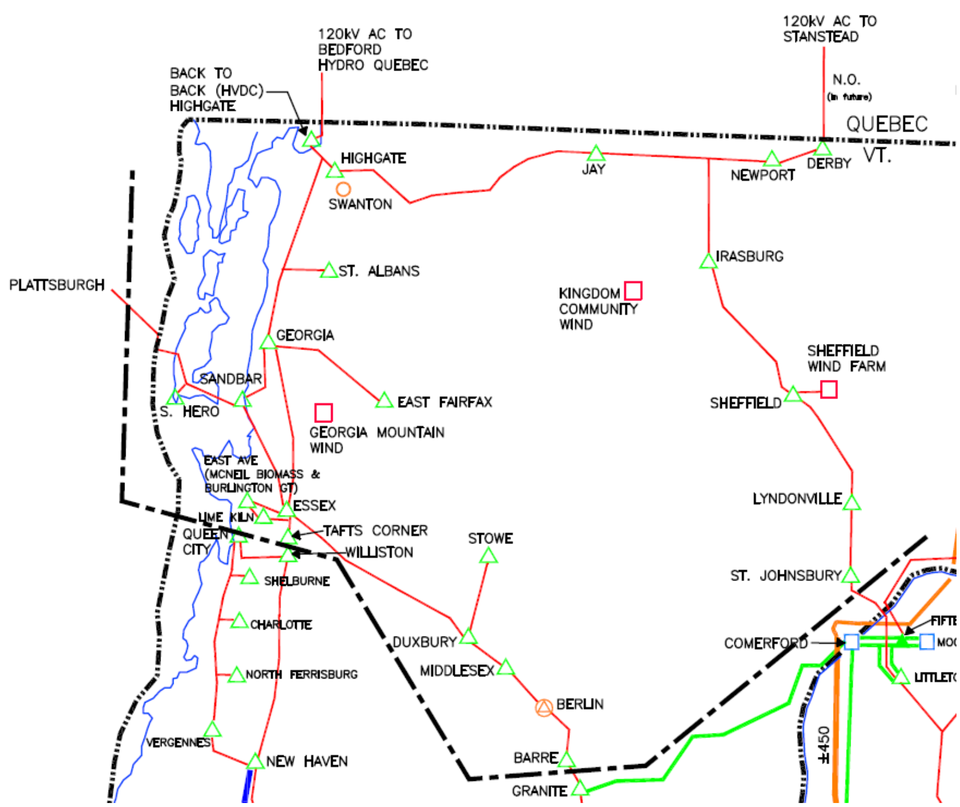
5 Discussion of peak demand results

The following section presents the findings on the bulk transmission system, which includes pool transmission facilities, for which costs are shared across the New England region through ISO-NE, as well as non-PTF facilities at voltages of 115 kV and above.

5.1 Bulk system issues

The electric grid will be designed based on the 2033 *VT Roadmap* load forecast with consideration of the 2043 study results since the *VT Roadmap* forecast reflects the scenario where Vermont is meeting its emissions reductions obligations. The *Continued Growth* load forecast scenario results are used to understand the effect on timing of system needs. No transmission overloads or voltage concerns were identified for single contingencies. All discussions below involve N-1-1 contingencies at the 2033 summer and winter VT Roadmap load scenarios unless otherwise noted. The transmission solution options are PTF because they involve networked transmission facilities. However, the implementation and funding of transmission solutions require ISO-NE agreement regarding the need and the solution. In fact, if the transmission is the preferred option versus non-transmission, and the need is beyond three years, ISO-NE will initiate a request for proposals, and the outcome of that RFP may be different from the solutions discussed in this Plan.

FIGURE 10 – NORTHERN VERMONT AREA OF CONCERN



The area north of the dashed black line illustrates the northern area for this analysis. It is bordered electrically by the Plattsburgh, Williston, Granite, and Littleton substations. At the 2033 summer VT Roadmap load level, the Barre transformer, Queen City transformer, Tafts Corner transformer, and several 34.5 kV lines overload due to loop flows towards the north. Loop flows are those flows circulating on parallel paths that may be unintended or undesired but that occur naturally based on system physics. In this case, the loop flows are on the sub-transmission system. One alternative is to disrupt these loop flows, and in some cases as many as three 34.5 kV lines would need to be tripped remotely by operator action, or these lines would trip due to line protection or unexpected line failure. While this approach works in a computer simulation for near-term conditions, it exposes the system to voltage collapse if the wrong 34.5 kV line is disconnected or the 34.5 kV lines are disconnected in the wrong sequence. On the transmission system, we are required to mitigate criteria violations. On the subtransmission system, the distribution utilities evaluate event probabilities to determine whether mitigation is warranted. This creates operational challenges and exposes the Vermont grid to severe criteria violations, and potentially voltage collapse, which would result in a blackout event. While we have modeled subtransmission line disconnection assuming that these lines will trip in a way that is planned or unplanned, we recommend that they be upgraded. With the expected significant increase in loads, there will be little margin for error. Therefore, as an overall design philosophy, we will propose transmission reinforcements that reduce the grid's reliability exposure to subtransmission failures.

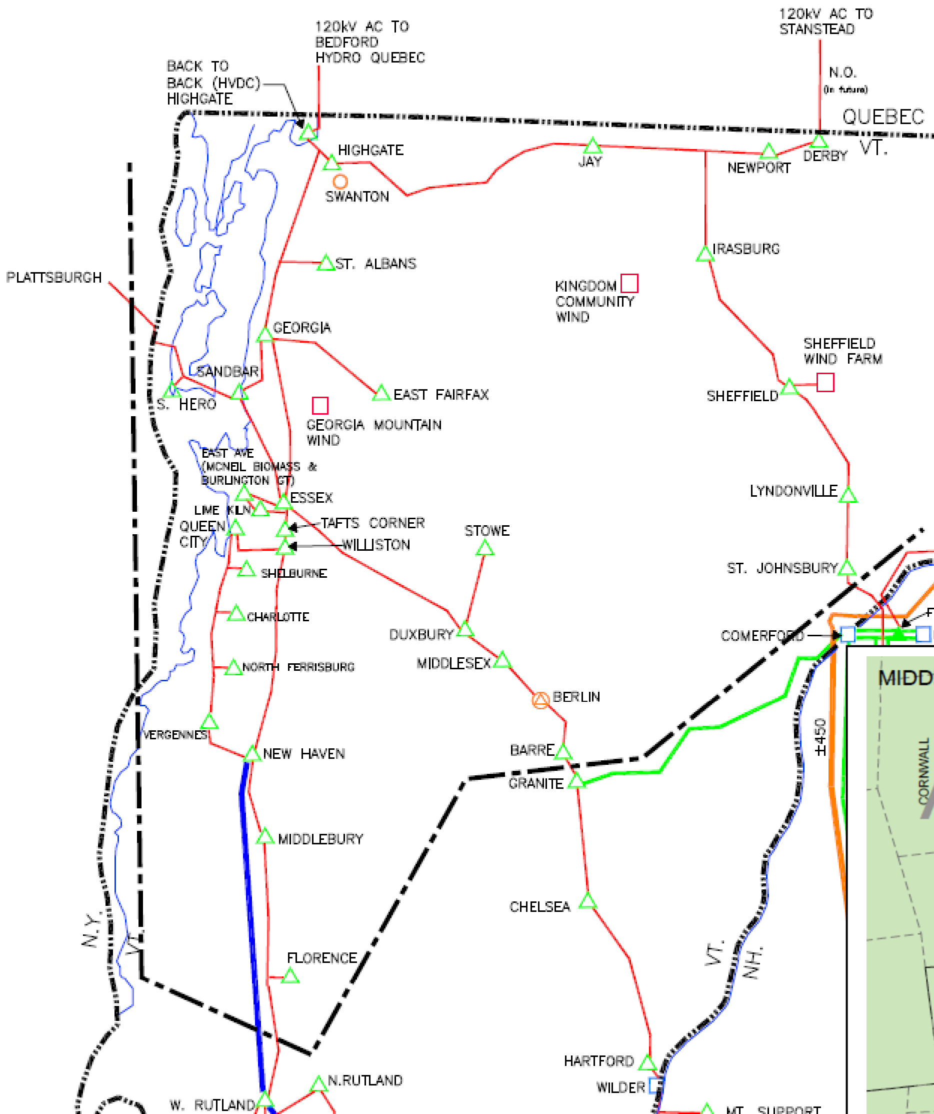
Since future winter peak loads are higher than summer peak loads, voltage collapse is more likely or will occur sooner under winter conditions. A voltage collapse can be avoided by careful dispatch of capacitor banks to achieve adequate reactive power reserves at the Essex substation between the first and second transmission contingencies. However, once an overloaded 34.5 kV line is tripped, planned or unplanned, voltage collapse was observed for the most severe N-1-1 contingency in the northern area, which indicates that the 2033 winter *VT Roadmap* load level is beyond what the system can reliably support.

The timing of the bulk system need is 2032 based on the winter *VT Roadmap* load forecast or 2038 based on the winter *Continued Growth* load forecast. The summer timing is 2034 based on the summer *VT Roadmap* load forecast or 2042 based on the summer *Expected Growth* load forecast. The transmission solution is to add a second transmission line between VELCO's Essex and Williston substations, shown in the image at the right in orange. The cost estimate for the project is $120M. Additional analysis is needed to confirm the final upgrade design.

FIGURE 10.1 –NORTHERN VT PROPOSED UPGRADE

The non-transmission alternative is to begin reducing the load to maintain the load below the projected 2032 winter peak load and the 2034 summer peak load. At the 2033 winter peak load level, the amount of load reduction was determined to be about 75 MW, and this load reduction will need to be located in an area that encompasses the following planning load zones: St. Johnsbury, Newport, Highgate, Johnson, St. Albans, Burlington Electric Department, IBM/GlobalFoundries, Montpelier, and Morrisville. Load reduction will have to begin a few years before 2033, and continue to grow beyond 75 MW after 2033 to keep pace with load growth. The NTA analysis will determine the design and implementation details of the NTA, and this is the case for all the NTAs discussed in the Plan. Since the reliability concern is associated with an N-1-1 contingency, load shedding could be initiated after the first contingency and before the second contingency, and remain disconnected until the first contingency has been restored or the load can no longer exceed the critical load level. Since the reliability concern involves voltage collapse and NTAs are just-in-time solutions with little margin, NTAs may not be viable or secure much beyond 2033. The affected utilities are all utilities, and the lead utility is GMP.

FIGURE 11 – NORTHWEST VERMONT AREA OF CONCERN



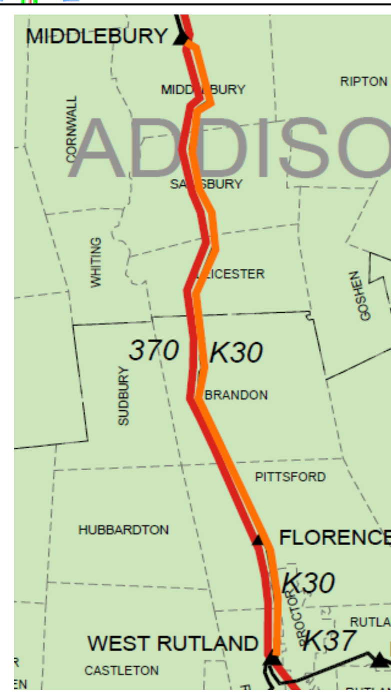


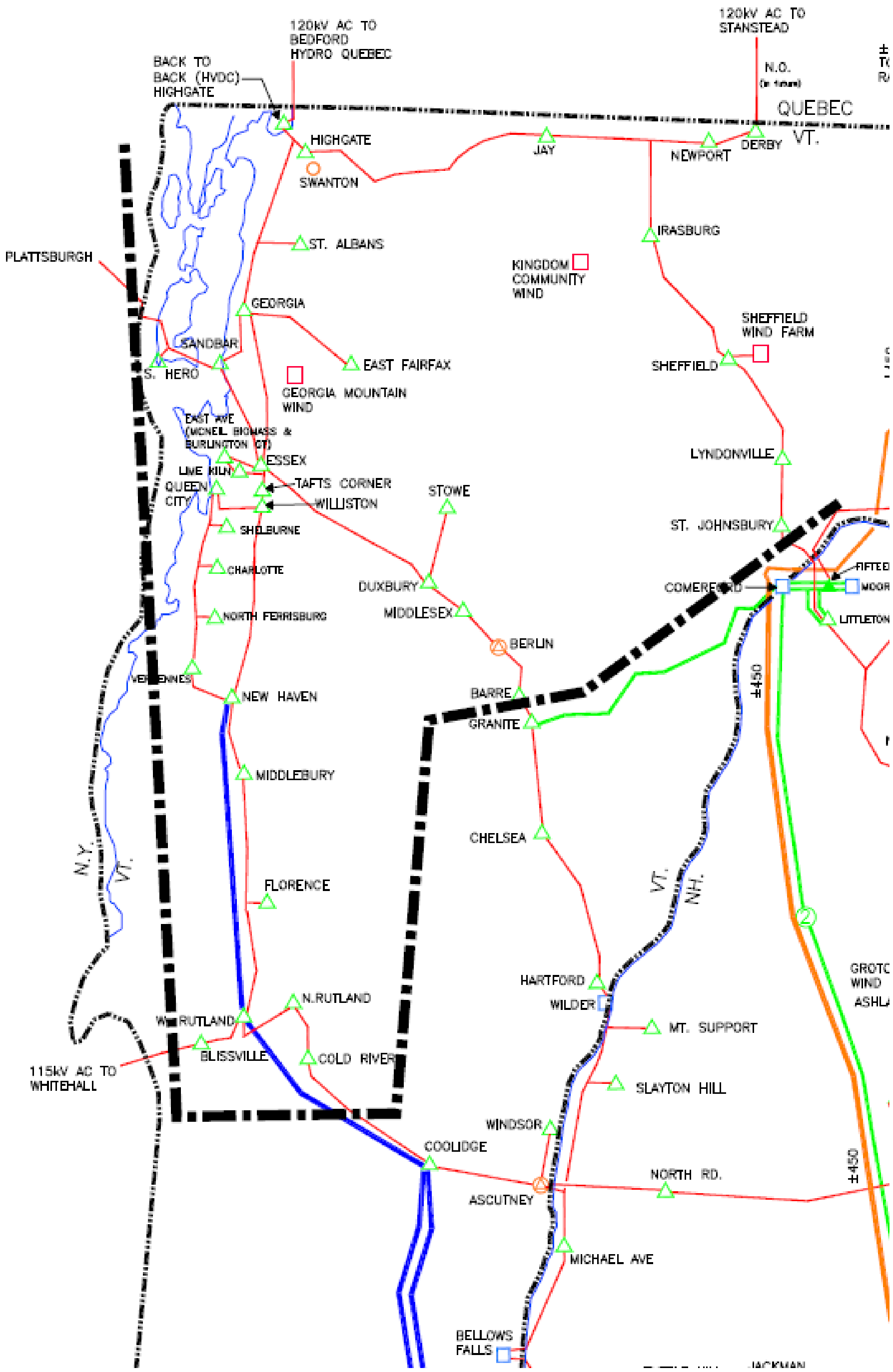
FIGURE 11.1 –NORTHWEST VT PROPOSED UPGRADE

The area north of the dashed black line illustrates the northwest Vermont area, which is bordered electrically by the Plattsburgh, West Rutland, Granite, and Littleton substations. At the 2033 summer *VT Roadmap* load level, the West Rutland to Middlebury 115 kV line, the Middlebury transformer and several 34.5 kV and 46 kV lines overload. It is assumed that subtransmission lines will trip either in a planned or unplanned fashion without resolving the transmission line overload.

The timing of the bulk system need is 2029 based on the summer *VT Roadmap* load forecast or 2033 based on the summer *Continued Growth* load forecast. The transmission solution is to increase the capacity of the West Rutland to Middlebury 115kV line shown in orange in the map insert to the right. The cost estimate for the project is $215M. The Middlebury transformer noted above may need to be upgraded as well. Additional analysis is needed to confirm the final upgrade design.

The non-transmission alternative is to begin reducing the load to maintain the load below the projected 2029 summer peak load. At the 2033 summer peak, the amount of load reduction was determined to be about 80 MW in an area that encompasses the following planning load zones: St. Johnsbury, Newport, Highgate, Johnson, St. Albans, GMP Burlington, Burlington Electric Department, IBM/GlobalFoundries, Middlebury, Florence, Montpelier, and Morrisville. Since the reliability concern is associated with an N-1-1 contingency, load shedding could be initiated after the first contingency and before the second contingency, and remain disconnected until the first contingency has been restored or the load can no longer exceed the critical load level. The affected utilities are all utilities, and the lead utility is GMP.

FIGURE 12 – CENTRAL VERMONT AREA OF CONCERN



The area north of the dashed black line illustrates the central area, which is bordered electrically by the Plattsburgh, Whitehall, Coolidge, Granite, and Littleton substations. At the 2033 summer *VT Roadmap* load level, the Coolidge to North Rutland 115 kV path and several subtransmission lines overload. This 115 kV overload was also identified in the ISO-NE 2033 Vermont Needs Assessment. The North Rutland, Cold River, and Windsor transformers, as well as New Hampshire and New York 115 kV lines overload depending on the N-1-1 contingency. The Blissville phase shifting transformer can be adjusted to eliminate the Vermont and New York 115 kV line overloads initially, but the tripping of overloaded subtransmission lines affect the transmission system negatively.

Following the tripping of subtransmission lines, the New York lines reached their capacity, which suggests that the timing of the central Vermont need is 2034 based on the 2033 summer *VT Roadmap* load forecast, or 2039 based on the 2033 summer *Continued Growth* load forecast.

The transmission solution is to increase the capacity of the Coolidge to Cold River to North Rutland 115 kV lines shown in orange in the map shared above. The cost estimate for the project is $185M. Additional analysis is needed to confirm the final upgrade design.

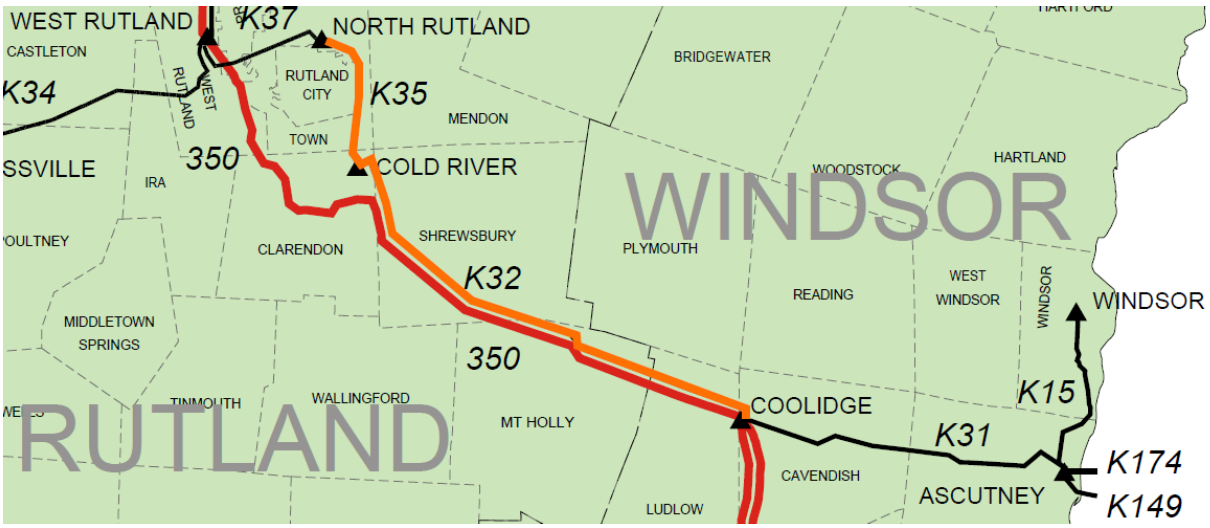
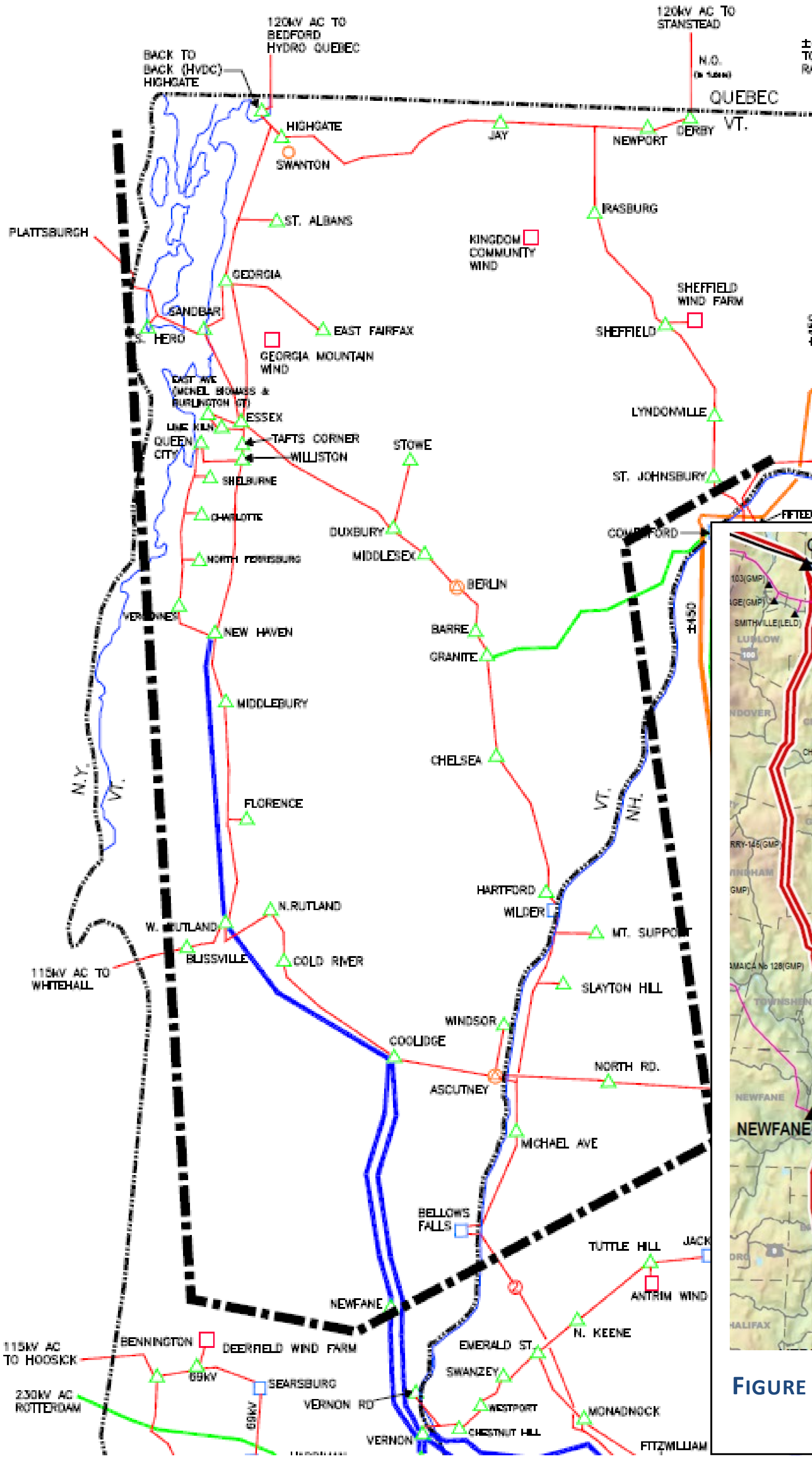


FIGURE 12.1 –CENTRAL VT PROPOSED UPGRADE

The non-transmission alternative is to maintain the load below the projected 2033 summer *VT Roadmap* load level, and specifically in an area that encompasses the following planning load zones: St. Johnsbury, Newport, Highgate, Johnson, St. Albans, GMP Burlington, Burlington Electric Department, IBM/GlobalFoundries, Montpelier, Morrisville, Middlebury, Florence, Central, and Ascutney. Since the reliability concern is associated with an N-1-1 contingency, load shedding could be initiated after the first contingency and before the second contingency, and remain disconnected until the first contingency has been restored or the load can no longer exceed the critical load level. The affected utilities are all utilities, and the lead utility is GMP.

FIGURE 13 – SOUTHERN VERMONT AREA OF CONCERN



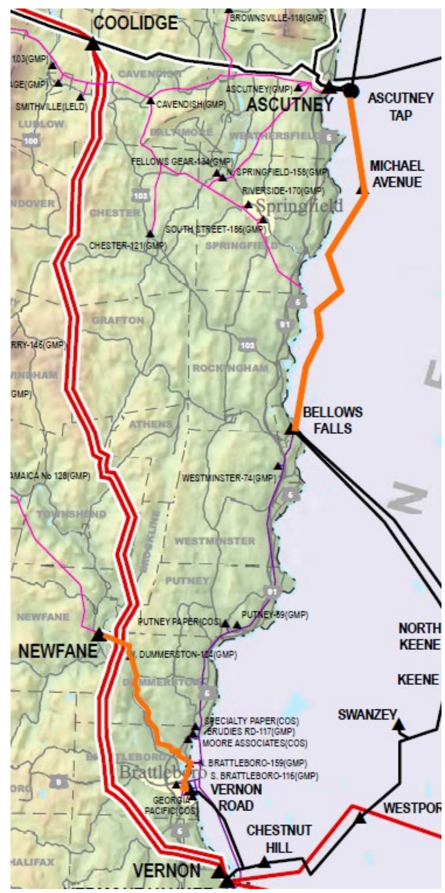


FIGURE 13.1 –SOUTHERN VT PROPOSED UPGRADE

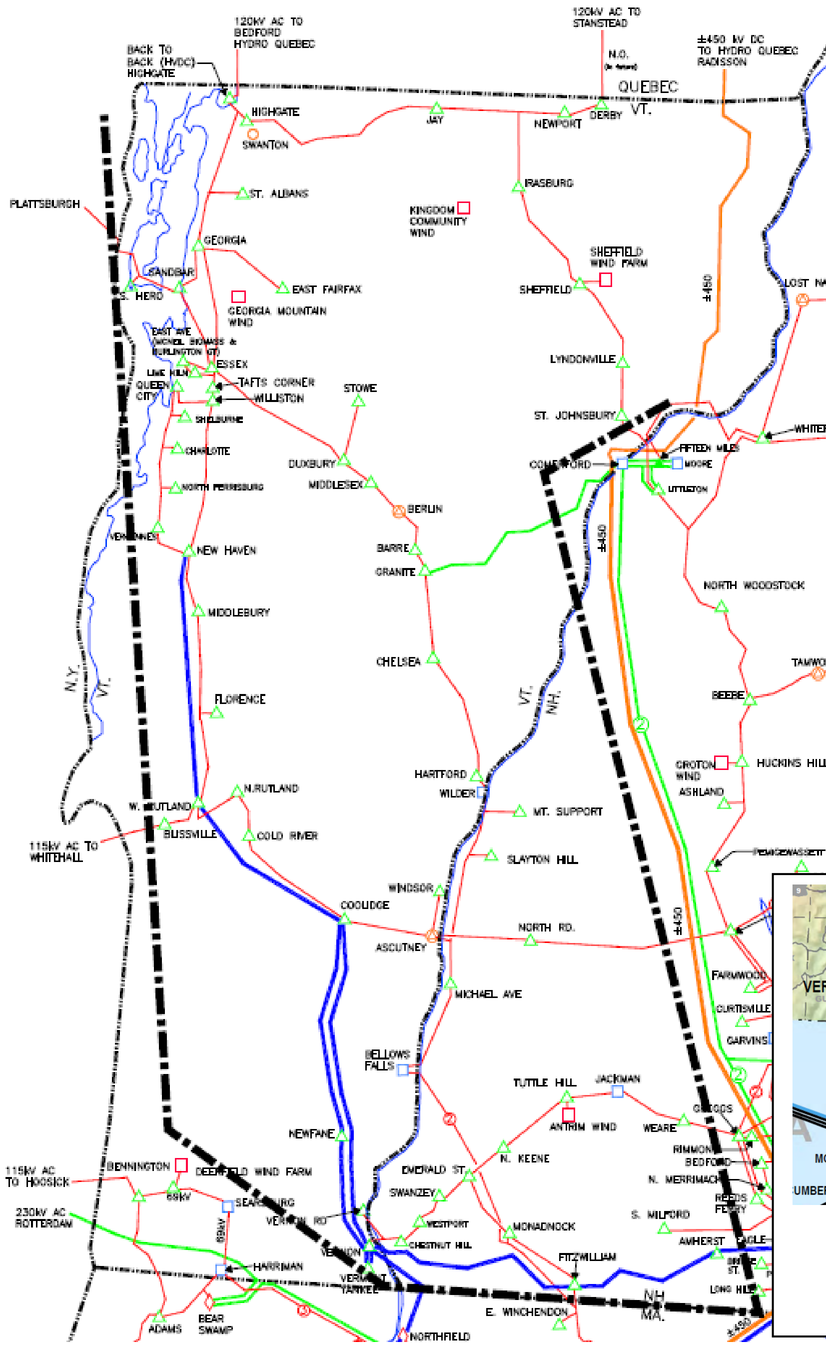
The area north of the dashed black line illustrates the southern area, which is bordered electrically by the Plattsburgh, Whitehall, Vernon, Monadnock, Webster, Comerford, and Littleton substations. At the

2033 summer *VT Roadmap* load level, New York 115 kV lines, the Vernon Road 115/46 kV transformer, and several 46 kV lines overload. Tripping the subtransmission lines and/or the Newfane 115/46 kV transformer eliminates the overloads, but this causes New Hampshire 115 kV lines to be at capacity, which suggests that the timing of the southern Vermont need is 2034 based on the 2033 summer peak *VT Roadmap* load forecast, or 2039 based on the 2033 summer *Continued Growth* load forecast.

The transmission solution is to increase the capacity of the Vernon Road to Newfane 46 kV line and the Bellows Falls to Ascutney Tap 115 kV line, which are not VELCO facilities, and therefore a cost estimate was not prepared. The transformers noted above may need to be upgraded as well. Additional analysis is needed to confirm the final upgrade design. This additional analysis may conclude that these upgrades have a short life, and a more robust upgrade, such as a 345 kV line from Coolidge to Deerfield, NH is the more appropriate upgrade.

The non-transmission alternative is to maintain the load below the forecast 2033 summer *VT Roadmap* load level for the state of Vermont. Since the reliability concern is associated with an N-1-1 contingency, load shedding could be initiated after the first contingency and before the second contingency, and remain disconnected until the first contingency has been restored or the load can no longer exceed the critical load level. The affected utilities are all utilities, and the lead utility is GMP.

FIGURE 14 – VERMONT AREA OF CONCERN



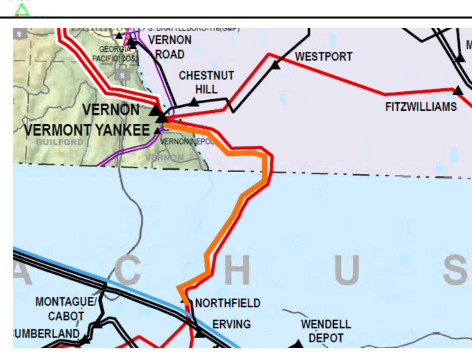


FIGURE 14.1 –VERMONT PROPOSED UPGRADE

The state of Vermont and southwest New Hampshire make up one electrically distinct area delimited by the dashed line on the above map. At the 2033 summer *VT Roadmap* load level, New York 115 kV lines near Whitehall, the Bennington 115/46 kV transformers, and several subtransmission lines overload. The Blissville phase shifting transformer can be adjusted to eliminate the New York 115 kV line overloads. Tripping the subtransmission lines eliminate the overloads, but Massachusetts 115 kV lines reach their capacity, which suggests that the timing of the southern Vermont need is 2034 based on the 2033 summer *VT Roadmap* load forecast, or 2039 based on the 2033 summer *Continued Growth* load forecast.

The transmission solution is to add a second 345 kV line between Vernon and Northfield shown above by the orange line in the map inset. VELCO owns a small section of the line to the Connecticut River. The cost estimate for the Vermont portion of the project is $5M. The transformers noted above may need to be upgraded as well. Additional analysis is needed to confirm the final upgrade design.

The non-transmission alternative is to maintain the load below the forecast 2033 summer *VT Roadmap* load level for the state of Vermont. Since the reliability concern is associated with an N-1-1 contingency, load shedding could be initiated after the first contingency and before the second contingency, and remain disconnected until the first contingency has been restored or the load can no longer exceed the critical load level. The affected utilities are all utilities, and the lead utility is GMP.

5.2 System issues classified as "predominantly bulk"

This section describes reliability issues classified as "predominantly bulk system," meaning they do not meet the definition of bulk system, but at least 50% of their cost elements are part of the bulk system. Projects that are proposed to address these issues involve a combination of grid elements owned by distribution utilities and elements owned by VELCO. Below is a description of the predominantly bulk issues identified in the first ten years of the planning horizon. All upgrades discussed in this section are non-PTF because they do not involve networked transmission facilities.

Several VELCO 115 kV transformers overload due to loop flows through the subtransmission system following a transmission outage. These overloads are not caused exclusively by local load but rather load in a much larger area served by the transmission system. In some cases, the transformer overloads can be addressed by opening transformers and subtransmission lines. In other cases, opening transformers and lines may result in load shedding, albeit less than the 300 MW ISO-NE threshold for resolution. A non-transmission alternative would be to disconnect an amount of load that is much larger than the size of the transformer. VELCO will need to coordinate with the relevant distribution utilities taking service from the transformer to determine whether a transformer upgrade is warranted or whether tripping subtransmission lines and loads is acceptable. It may be more appropriate to mitigate the worst subtransmission line overloads and those that occur for a large number of outages.

Thermal results for single transmission line and transformer contingencies:

St. Albans transformer

> At the 2033 summer *Continued Growth* load forecast, the St. Albans transformer was found to be overloaded in our analysis. The rating of this transformer is limited by the 34.5 kV bus, and we expect the rating to increase by using the rigid bus rating methodology outlined in the IEEE 605 standard, which will eliminate the transformer overload.

Queen City transformer

> This transformer and a subtransmission line overload at the 2033 summer *VT Roadmap* load forecast for a transmission line outage.
>
> The timing of this overload is 2027 based on the 2033 summer *VT Roadmap* load forecast or 2030 summer *Continued Growth* load forecast. This transformer also overloads for N-1-1

contingencies, and this N-1 concern is addressed as part of the N-1-1 solution as discussed in the northern area portion of the bulk system section.

The non-transmission alternative would involve maintaining loads below the 2027 summer *VT Roadmap* load, and to disconnect roughly 100 MW of load by 2033 north of Burlington in an area encompassing several northern load zones, such as St Johnsbury, Newport, Highgate, St Albans, Johnson, IBM/GlobalFoundries, and Burlington Electric Department.

Ascutney transformer

This transformer and several subtransmission lines overload at the 2033 summer and winter *VT Roadmap* load scenario for an equipment failure that would disconnect an entire substation owned by National Grid. The solution proposed for this concern is to disconnect load by operator action in the Bellows Falls area. The transmission solution alternative is to rebuild the relevant substation to a breaker-and-a-half configuration whose design prevents the problematic contingencies.

Transformers at Barre, Bennington, and North Rutland overload at the 2043 summer *VT Roadmap* load forecast for a single contingency. No solution is proposed at this time due to the timing being later than ten years. The Cold River and Windsor transformers were within 5% of their capacity at the 2043 summer *VT Roadmap* load forecast. The Cold River, Vernon Road, Middlebury, and Irasburg transformers were within 5% of their capacity at the 2043 winter *VT Roadmap* load forecast.

N-1-1 contingency result summary:

Several transformers overload following an N-1-1 contingency. Although the transformer overloads could be characterized as a predominantly bulk concern, the issue should be characterized as a bulk system concern due to the potential for cascading to the transmission system. These concerns are discussed in the bulk system section above. The transformers and associated subtransmission lines overloaded for N-1-1 contingencies are noted below:

- Barre transformer: Queen City to Digital, Barre to North End
- Queen City transformer: Marshfield to Danville, Queen City to Digital, Websterville to Legare
- Tafts Corner transformer: Digital to Essex
- Middlebury transformer: Seminary St to Agrimark Tap
- Cold River transformer: Cold River to South Rutland, Blissville to Hydeville, Marshfield to Danville
- North Rutland transformer: North Rutland to Brandon, Marshfield to Danville
- Windsor transformer: Windsor V4 to Taftsville
- Vernon Rd: South Street to Pole 170, Vernon Rd to Newfane

5.3 Subsystem issues

This section describes reliability issues classified as "subsystem" meaning they do not meet the definition of bulk transmission system, and they are not intended to serve radial distribution loads. If the affected distribution utilities determine that these issues require resolution, these projects would involve grid elements owned by distribution utilities. Subsystem results are based on N-1 contingencies.

VELCO's identification of issues on the subsystem requires the assistance of local distribution utilities. VELCO coordinates closely with local distribution utilities during the preparation of the Plan to identify relevant issues and share information about study findings. In cases where information about a subsystem issue is not available to VELCO in time for a three-year update of the Plan, some reliability concerns may not be included in the Plan. Additionally, distribution utilities make changes to their systems from time to time to better serve customers. These changes can be made quickly, and it is difficult to predict and model all of those changes during the performance of these studies. In such cases, reliability concerns on the subsystem may not be identified as part of the Plan.

The analysis identified issues that are categorized as causing a high or low voltage, or a thermal overload in which equipment exceeds its rated temperature. These subsystem findings are based on VELCO's statewide analysis. System analysis by the affected utilities using different reliability criteria, localized forecasts, and a specific focus on subsystem performance may produce different results. Flexibility is permitted at the subsystem level concerning the reliability criteria the system must meet because the sub-transmission system is not currently subject to mandatory federal reliability standards. For example, a utility may accept the impacts of an infrequent power outage rather than invest in infrastructure to eliminate the power outage risk based on its analysis of costs, benefits, and risks. The affected utilities will determine what, if any, projects are required to address the potential reliability issues on the sub-transmission system, or whether these concerns can be addressed with a non-wires solution.

Voltage results for single-element transmission line and transformer contingencies:

> The most severe low voltage concern was found in the Dorset 46 kV area for a single-element contingency at the 2033 summer *Continued Growth* load level. This low voltage exists today, and has been identified in prior long-range Plans.
>
> The second low voltage issue was found near the Sherburne area, which occurred for a single-element contingency at the 2033 winter *VT Roadmap* load level. This low voltage concern is associated with winter load conditions.

Thermal results for single-element transmission line and transformer contingencies:

> At the 2033 summer *Continued Growth* load level, there were overloads on a 46 kV line out of the VELCO Windsor substation, a 34.5 kV line out of the GMP Ballard substation, and a 34.5 kV line out of the GMP Gorge substation.
>
> At the 2033 summer *VT Roadmap* load level, there was an overload on a 34.5 kV line out of the VELCO Queen City substation.
>
> At the 2033 winter *Continued Growth* load level, there was an overload on a 34.5 kV line out of the Marshfield substation. This overload is particularly concerning because it can contribute to transmission level criteria violations as discussed in the bulk system section above.

The following table lists sub-transmission thermal and voltage results chronologically for review by the distribution utilities.

TABLE 6 – SUBTRANSMISSION POTENTIAL RELIABILITY ISSUES

Sub-Transmission Potential Reliability Issues					
Year Needed	**Contingency**	**Reliability Concern**	**N-1 Criteria Violation**	**Affected DUs**	**Lead DU**
2023	Transformer/Subtransmission Open End/Pickup	Thermal	McNeil-Gorge-Ethan Allen McNeil-Iroquois-Ethan Allen	GMP/ BED	GMP
2023	Subtransmission Open End	Thermal	Maple Ave-Claremont Sol Waste	GMP/Eversource	GMP
2023	Subtransmission Line Out	Thermal	Londonderry-Jamaica-Newfane	GMP	GMP
2023	Double Circuit Contingency	Low Voltage	Stowe-Morrisville-Hardwick	GMP/Stowe/ Morrisville/ WEC/Hardwick	GMP
2023	Subtransmission Line Out	Thermal	East Arlington-Manchester	GMP	GMP
2023	Subtransmission Pickup	Thermal	Ryegate Transformer	GMP	GMP
2023	Subtransmission Pickup	Thermal	Newbury-Woodsville-Wells River	GMP	GMP
2023	Transformer	Low Voltage	Blissville Area	GMP	GMP
2023	Transmission Line	Thermal	Danville	GMP/WEC	GMP
2023	Transformer	Thermal	West Rutland-Castleton-Hydeville	GMP	GMP
2023	Transformer	Low Voltage	Thetford-Ely	GMP	GMP
2025	Subtransmission Open End	Thermal	Highbridge-Ascutney	GMP	GMP
2025	Subtransmission Open End	Thermal	Montpelier-W.Berlin-Northfield	GMP/Northfield	GMP
2025	Subtransmission Open End	Low Voltage	Moretown-Irasville-Northfield-West Berlin	GMP/WEC/ Northfield	GMP
2026	Subtransmission Open End	Thermal	Moretown-Bolton Falls	GMP	GMP
2027	Subtransmission Line Out/Open End/Pickup	Low Voltage	Barre Area	GMP	GMP
2027	Subtransmission Open End/Line Out	Thermal	Bellows Falls-Vilas Bridge	NGrid/GMP	GMP
2027	Transmission Substation	Low Voltage	Bellows Falls-Vilas Bridge	NGrid/GMP	GMP
2027	Subtransmission Pickup	Thermal	South Brattleboro-Vernon	GMP/NGRID	GMP
2027	Subtransmission Open End	Low Voltage	Bellows Falls-Joy-Lafayette St	NGrid/GMP/ Eversource	GMP
2027	Transformer/Subtransmission Open End	Thermal	Windsor	GMP	GMP
2028	Subtransmission Open End/ Pickup/Line Out	Thermal	Websterville-South Barre	GMP	GMP
2028	Subtransmission Line Out	Low Voltage	Byrd Ave-Claremont Solid Waste	GMP/Eversource	GMP
2029	Subtransmission Open End	Low Voltage	Morrisville-Wolcott-Hardwick-Walden	GMP/Morrisville	GMP
2030	Subtransmission Open End/Pickup/Line Out	Thermal	South End-Barre	GMP	GMP
2030	Transmission Line/ Subtransmission Open End	Thermal	Marshfield-Danville	GMP/ WEC	GMP
2030	Subtransmission Line Out/ Open End	Low Voltage	Essex-Sand Road-Richmond	GMP	GMP
2031	Subtransmission Open End/ Pickup	Low Voltage	Ethan Allen	GMP	GMP
2031	Transformer/Subtransmission Open End	Low Voltage	Bethel-Randolph-Stockbridge	GMP	GMP
2031	Generator Out	Low Voltage	Newbury-Woodsville-Wells River	GMP	GMP
2032	Subtransmission Open End	Low Voltage	East Montpelier	GMP/WEC	WEC
2032	Subtransmission Pickup	Low Voltage	Richford-East Berkshire	VEC	VEC
2032	Transmission Substation	Low Voltage	Mt. Knox	WEC/GMP	GMP
2033	Transformer	Low Voltage	Sheldon	GMP	GMP
2033	Subtransmission Open End	Low Voltage	Woodstock	GMP	GMP

The subsystem near the Stowe substation is served from the south by a transmission line and a subtransmission line located on the same set of poles, as required by the Section 248 permit for the Lamoille County Project. A double-circuit contingency disconnecting both supplies was found to cause low voltage issues in 2023. Since the Lamoille County Project was permitted with the preferred double circuit design, this low voltage is not considered a concern that needs mitigation.

While we understand that distribution utilities design the subtransmission system based on single-element contingencies, the performance of the subtransmission system under multi-element and coincident transmission contingencies is increasingly concerning due to the negative cascading impacts on the transmission system. Below is a list of subtransmission lines that overload, aggravate, cause, or are associated with low voltages and thermal overloads on the bulk and predominantly bulk systems:

- Barre transformer: Queen City to Digital, Barre to North End
- Queen City transformer: Marshfield to Danville, Queen City to Digital, Websterville to Legare
- Tafts Corner: Digital to Essex
- K30 line: Marshfield to Danville, North Rutland to Brandon
- Middlebury transformer: Seminary St to Agrimark Tap
- K32 line: Marshfield to Danville, Websterville to Legare
- Cold River transformer: Cold River to South Rutland, Blissville to Hydeville, Marshfield to Danville
- North Rutland transformer: North Rutland to Brandon, Marshfield to Danville
- Windsor transformer: Windsor V4 to Taftsville
- Vernon Rd: South Street to Pole 170, Vernon Rd to Newfane
- Comstock-Mohican: Manchester to Wallace

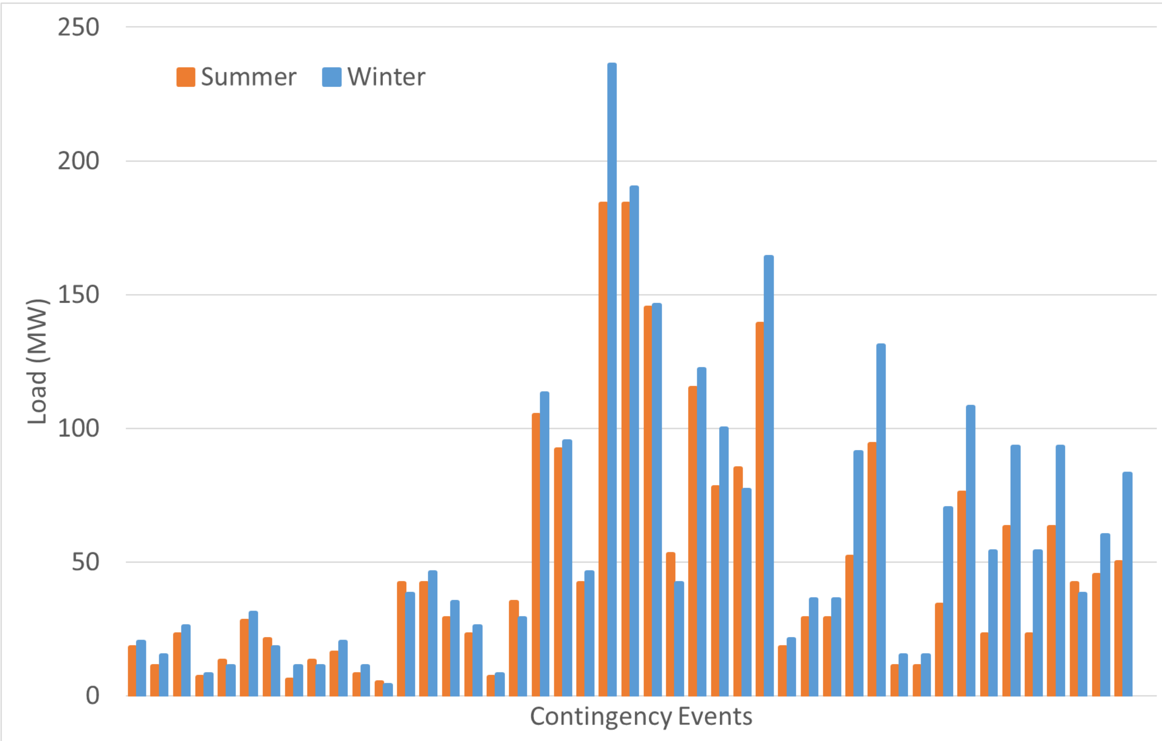
5.3.1 Load disconnection

The Vermont system is exposed to loss of load that ISO-NE has determined to be acceptable based on the proposed guideline for pool funding of transmission (PTF) projects. In essence, ISO-NE ensures that no adverse impacts to PTF assets arise under such circumstances. The proposed ISO-NE guideline, which was not finalized but is being applied, states that up to 100 MW of load loss is potentially acceptable for single outage events, and up to 300 MW of load loss is potentially acceptable for N-1-1 outage events. Following the completion of the last transmission reliability project completed by VELCO, the Connecticut River Valley Project, as outlined in the 2015 long-range Plan, none of the load loss exposures exceed these thresholds. There is some amount of risk that the sequence of line tripping in an actual emergency event will be different from the sequence that was modeled in our analyses. Subtransmission lines could have weak points that let go under lower levels of overloads. There may be subtransmission line protection that could trip the lines intentionally or unintentionally. In these cases, a larger region would be affected and more load could be disconnected. Planning risk assessments would consider mitigating the worst subtransmission line overloads and those that occur for a large number of outages, but as the peak load increases, the margin for error becomes slimmer.

In the ISO-NE Needs Assessment noted four N-1-1 contingencies that led to load disconnection varying from 160 MW to 250 MW at the winter 2033 peak load level. These and other load shedding events will not be resolved.

Below is a graph showing some of the load disconnections caused by N-1 and N-1-1 contingencies. In cases where several contingencies result in the same load loss, only one representative contingency load loss was plotted. Each summer and winter load loss pair is associated with one contingency.

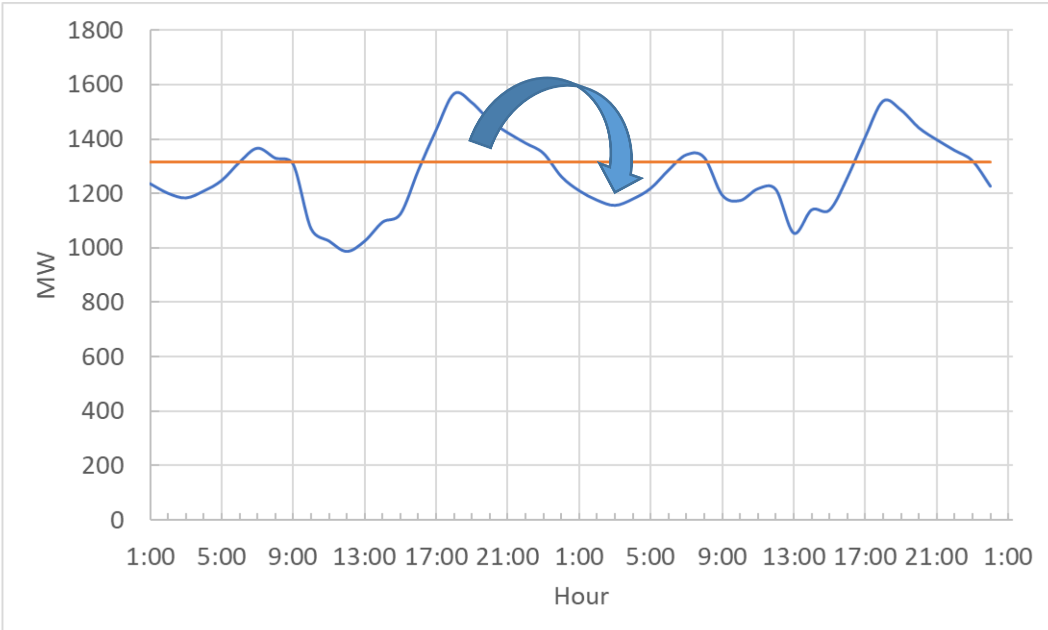
FIGURE 15 – LOSS OF LOAD RESULTS NOT BEING RESOLVED



5.3.1.1 Planned load control

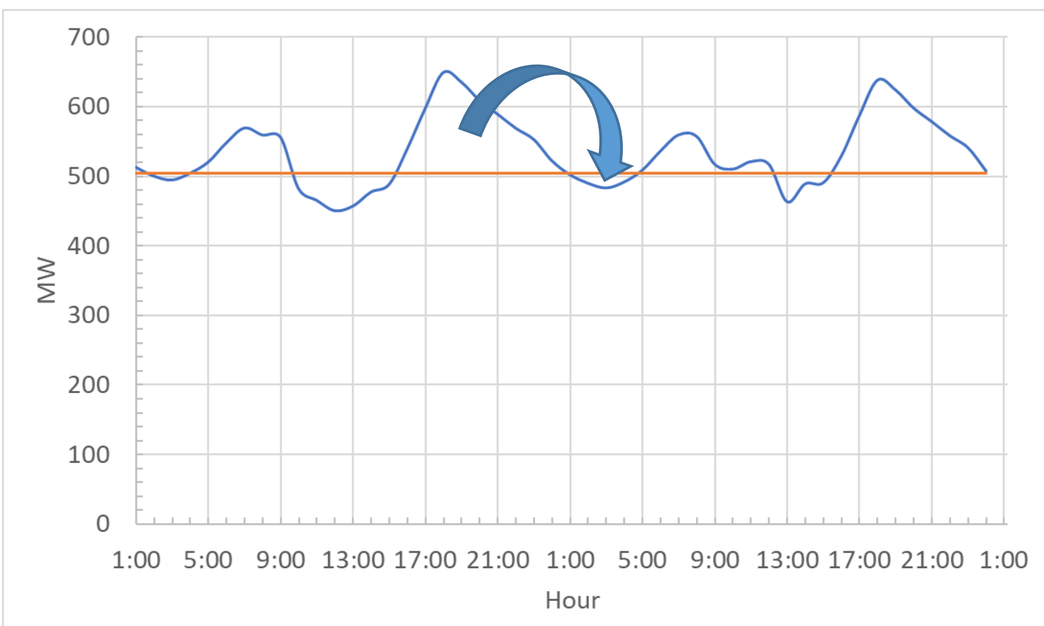
Load control, load management, load flexibility, voluntary load curtailment, storage, demand response, microgrids, and similar load reduction means are and will continue to be critical resources to address system performance concerns. Experience shows that many customers agree to participate in time-of-use programs, and we have assumed that this will continue as more Vermonters consume electricity for heating, transportation, and other uses. In the 2021 Plan, we assumed that 75% of new EV loads can be disconnected during critical peak-load periods. In this Plan, we illustrate that load control will become more complicated and potentially less viable as load grows. Using the northern area bulk system concern discussed above as an example, we show that we may be able to maintain the state peak load below the critical load level, calculated to be 1314 MW, subtracting 75 MW from the 2033 winter peak forecast of 1389 MW. The following graph covers two sequential days and suggests visually, by trying to fit the peak above the critical load (orange line) into the valley to its right, that if customers cannot charge their EVs between the hours of 4pm and 11pm on the peak day, the EVs may be sufficiently charged from midnight to 5am. In this example, the load control measure would be triggered at 3pm and continue until 11pm.

FIGURE 16 – LOAD CONTROL AT THE 2043 WINTER PEAK STATEWIDE



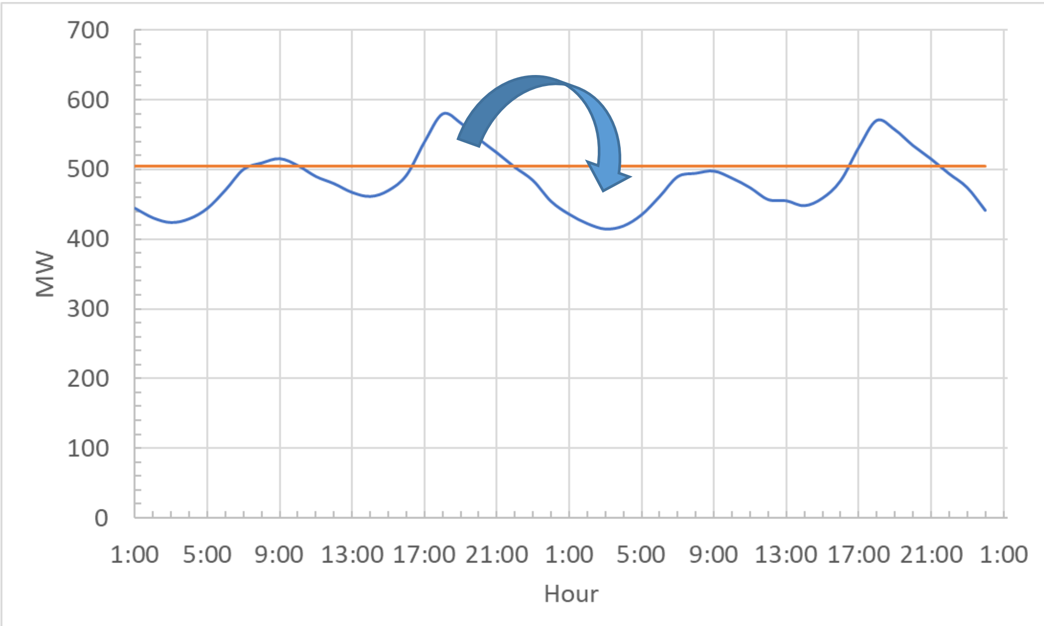
The effectiveness of load control depends on the location of the load being controlled. As noted in the northern area discussion above, the location of the loads needs to be in the following planning zones: St. Johnsbury, Newport, Highgate, Johnson, St. Albans, BED, IBM/GlobalFoundries, Montpelier, and Morrisville. If we remove the entire 75 MW from these zones, we see the following:

FIGURE 16.1 – LOAD CONTROL AT THE 2043 WINTER PEAK IN NORTHERN AREA ALONE



The above graph suggests that there will not be sufficient hours to charge EVs the day after a load control event during a multi-day cold spell. This may mean that the EV load control needs to be supplemented with some other load control mechanism. Part of the reason why load control becomes increasingly difficult is that we expect loads to grow at all hours, and the amount of load that needs to be removed during the peak hours also increases in order to remain below the critical load level. During the 2033 peak, the northern area looks as follows:

FIGURE 16.2 – LOAD CONTROL AT THE 2033 WINTER PEAK IN NORTHERN AREA ALONE



The above graphs illustrate that while load control may be effective during the first few years of the program, it may be difficult to find enough hours to fit the displaced energy in the case of flexible load management or enough hours to charge battery storage systems to prepare them for deployment during a reliability event.

5.3.2 USE OF GRID-ENHANCING TECHNOLOGIES (GETS)

At this point, it does not appear that the transmission solutions proposed to address the identified reliability will include the use of grid-enhancing technologies. The US Department of Energy (DOE) has offered a definition of GETs that include dynamic line ratings, flow control devices, and supporting analytical tools, such as sensors, smart meter, and monitoring devices. We would expand the definition to include technologies that improve the flexibility and the resilience of the system, help to avoid or minimize operational concerns, such as congestion and generation curtailment, and help defer or reduce the scale of transmission reinforcements. VELCO has experience with analyzing and implementing these technologies when appropriate. We have considered dynamic line ratings and specialized conductors, such as carbon core conductors, but we have determined that they are unnecessary at this time or we have found more cost-effective options to meet current needs. We are currently pursuing use of a SmartValve to supplement the Sand Bar phase shifting transformer, which control flows along the Plattsburgh-Sand Bar 115 kV PV20 line. A SmartValve is a power electronics device that controls flow in a more precise way than PSTs. The SmartValve will address the asset condition concerns with the phase shifting transformer (PST). A phase shifting transformer located at the Plattsburgh end of the line failed three times over a seven-year period, and the PST at Sand Bar failed after fifteen years of performance, which is quite short for a transformer. There are other benefits from the use of a SmartValve, including increased control range, more precise control, and increased delivery of renewable energy from New York. DOE awarded money to the Electric Power and Research Institute, who partnered with VELCO through the Grid Resilience and Innovation Program to support the installation of a SmartValve on the PV-20 line. We are currently seeking the necessary regional approvals as an eligible asset management investment eligible for cost-share support in order to fulfill the grant's matching funding requirement.

With respect to our history with grid enhancing technologies, VELCO installed a STATCOM at our Essex substation and synchronous condensers at our Granite substation when such technologies were relatively new. In the absence of Vermont generators that can provide voltage control services, these devices provide voltage control in a similar way as generators except that they do not use any fuel and do not need a turbine that provides mechanical energy. Even now, the synchronous condenser vendor uses our Granite facilities as a project demonstration for potential customers all over the world. VELCO installed PSTs at Sand Bar, Granite, and Blissville as part of the Northwest Reliability Project completed in 2006. PSTs use transformer technology with the winding arranged in such a way to allow flows to be pushed to or pulled from parts of the system. These PSTs were proposed to optimize flows from our neighbors without overloading their facilities, and this deferred additional upgrades for several decades. As discussed in the results section of the Plan, the PSTs are still being used to defer upgrades that ultimately may be needed roughly ten years from now.

5.3.3 ISO-NE Needs Assessment

At a high level, the conclusions of the ISO-NE Needs Assessment are similar to those of the Vermont Long-Range Transmission Plan, but there are some differences due to several factors. First, the planning horizon of the ISO-NE study is 10 years. Second, the load forecast is different in terms of load level and load distribution. The 2033 winter peak forecast is 3% higher, 1431 MW versus 1389 MW. For the summer peak forecast, ISO-NE assumes that heat pumps have no effect on cooling load. The 2017 Vermont Cadmus load study was not sufficient to meet ISO-NE's HP cooling data specifications. ISO-NE planners model active demand response homogenously across the state. These differences don't account for the entire load forecast discrepancy, but the ISO-NE studies modeled a much lower summer load, 942 MW versus 1195 MW. Third, ISO-NE allocates the statewide forecast, including energy efficiency, demand response, and solar PV on the bus-by-bus load distribution based on the most recent historical load distribution. The long-range Plan forecast is done at a zonal level and then rolled up to the state level. This results in a redistribution of loads due to zonal adoption of EVs and heat pumps. Fourth, the ISO-NE study focuses on the pool transmission facilities. The subtransmission system is not monitored and the possible tripping of subtransmission lines is not considered. As a result, the subsequent negative transmission impacts cannot be observed. This is another reason why we recommend that overloaded subtransmission lines caused by transmission contingencies be upgraded. Fifth, ISO-NE did not use a true winter case. ISO-NE created a 2032-2033 winter peak case by starting with a 2032 summer peak case and making the following modifications:

- Adjusting New England load, energy efficiency, active demand/response, and PV forecast assumptions;
- Reflecting winter ratings of transmission facilities within New England; and,
- Adjusting the New England conventional generator outputs from Summer qualified capacity to Winter network resource capability.

The result of these modifications is that the New York system is modeled to represent a summer load level and load distribution. This can downplay the interactions between New York and Vermont.

Even with these differences, ISO-NE identified a system need similar to the central Vermont concern described in the bulk system section above. ISO-NE also identified a voltage collapse exposure along the Bennington to Vernon line. This issue was more severe than in the long-range analysis possibly due to a different load representation. The voltage collapse occurred for an N-1 transmission contingency in the ISO-NE study, while the voltage collapse occurred for an N-1-1 contingency in the long-range Plan analysis.

One major difference is that the ISO-NE Needs Assessment included stability and short circuit analyses. Short circuit studies seek to identify circuit breakers whose interrupting capability is exceeded by the available fault currents, and there were no issues in Vermont. These results were expected as there is very little generation in Vermont. The stability results pointed to the potential for Vermont distributed generation to trip unexpectedly for transmission faults likely because of protection and control settings that are inconsistent with the IEEE 1547-2018 standard and the ISO-NE Source Requirement Document. ISO-NE plans to perform a New England-wide study this year because of the regional implications of distributed generation tripping, and it also plans to develop solutions that may involve transmission upgrades in Vermont.

6 Discussion of DG (solar PV) results

6.1 Summary of generation hosting analysis

Generation hosting analysis was conducted on the Vermont system in 2018, 2021, and again in the 2024 Vermont Long-Range Transmission Plan. The assumptions behind the analysis have varied to some degree, while the fundamental findings remain on trend. The table below shows how the assumptions have evolved for the generation hosting analysis across each iteration of the long-range Plans.

TABLE 7 – STUDY ASSUMPTIONS FOR GENERATION HOSTING CAPACITY ANALYSES

Study Year	**2018**	**2021**	**2024**
Sandbar PST Imports (MW)	0	50	50
Highgate HVDC Imports (% Output)	100	100	100
Granite PST Imports (MW)	100	0	50
Renewable Generator Resources (% Output)	100	100*	100*
Non-Renewable Generator Resources (% Output)	0	0	0
Gross Load Level (MW)	675	560	650
Studied DG Levels (MW)	500, 1000	500, 600, 700, 800, 900, 1000, 1100, 1200, 1250	500, 600, 700, 800, 900, 1000, 1100, 1200, 1300

*All hydro, wind, wood, and methane generators were modeled at 100% output, while KCW was reduced to 90% output to assist in conjunction with the PV20 output, which resulted in a base case overload along the western North-South transmission corridor.

Throughout all of the generation hosting analyses, common themes have developed that remain true across each iteration.

1. Location of DG installations matters. There are numerous ways to study solar PV growth across the system. Every iteration of the hosting analysis examined solar PV growth assuming a geographical distribution similar to the existing distribution system wide and also an optimized distribution where solar PV is located specifically to avoid additional system constraints. Each iteration has shown that Vermont is rapidly approaching thermal capacities on its transmission system on the spring light-load days, i.e., high renewable generation paired with low system load, when additional installations are sited in a manner similar to the existing geographical distribution. Through optimizing the location of additional installations, the system can accommodate much more DG before needing to resolve a transmission or subtransmission constraints.
2. System losses increase significantly when in-state generation outpaces Vermont system load. Once Vermont produces more energy than can be used in-state, the power produced must

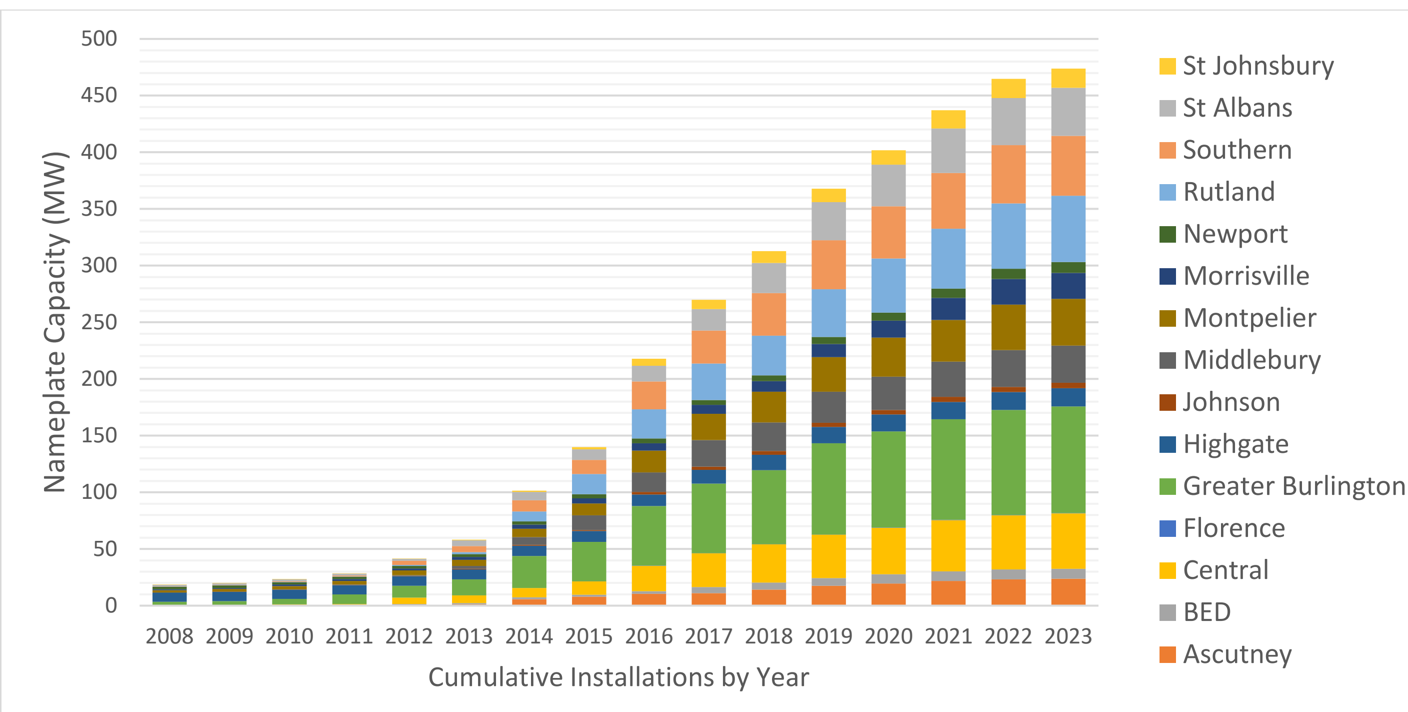
travel across the subtransmission and transmission systems to be absorbed outside of Vermont. Transmitting this power long distances leads to additional system losses.

3. Using Tier II targets, the transmission and subtransmission systems of Vermont cannot adequately accommodate the projected targets of installed DG without addressing the system constraints. There are many opportunities to address the constraints due to high DG, but these require collaboration throughout Vermont to develop policies and programs to accomplish an optimized solution which could use any combination of the following tools, which could incur additional costs to Vermonters:
    - DG siting incentives/disincentives;
    - Energy storage solutions;
    - Flexible load management;
    - Energy production curtailment;
    - Demand response; and,
    - Transmission and subtransmission system upgrades.

6.2 Vermont Distributed Solar PV Growth

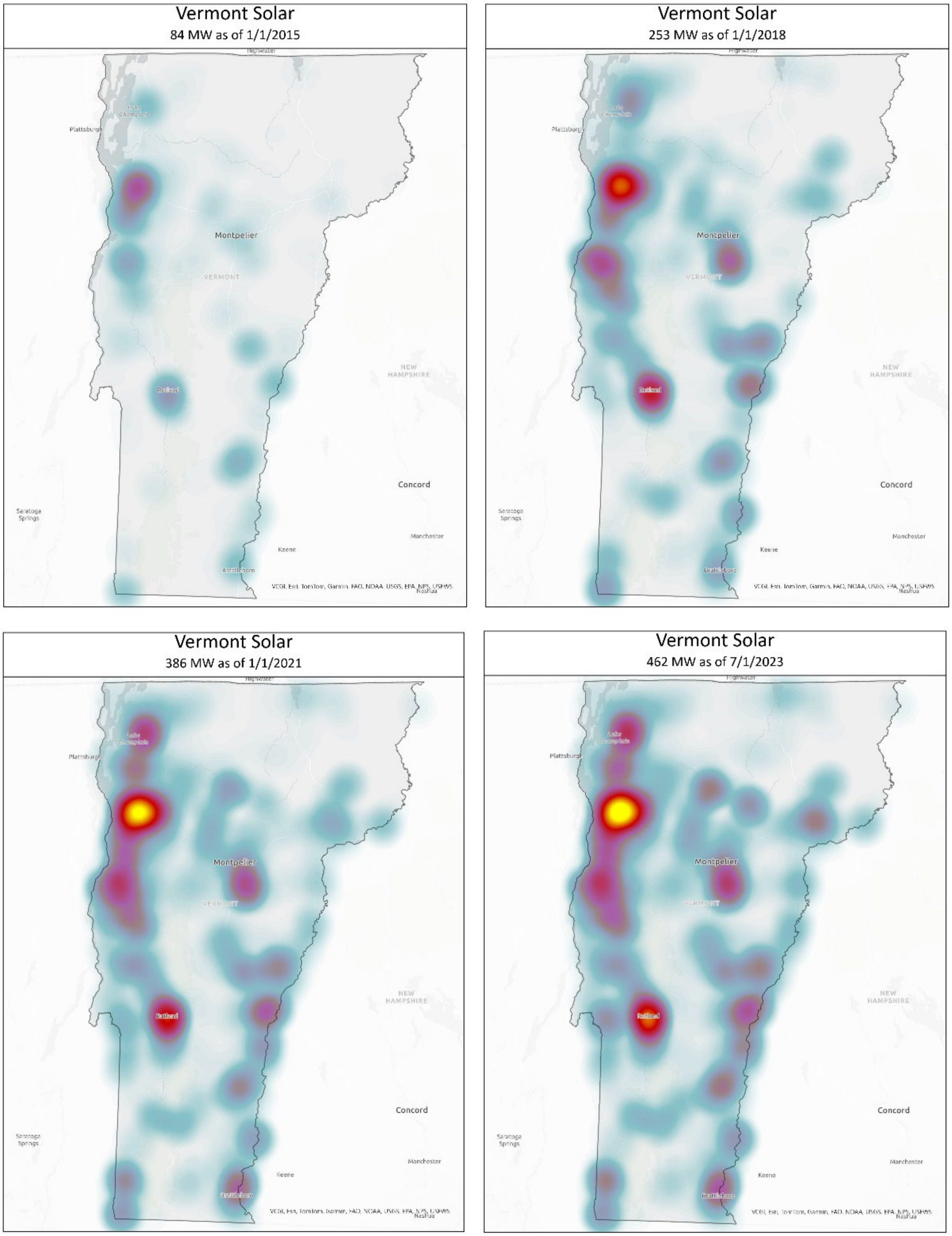
One of the major assumptions in the analysis is the future geographical distribution of solar PV as it grows from about 500 MW to potentially 1,300 MW. The analysis started with the geographical distribution as of July 2023 where the total amount of solar PV was approximately 485 MW with an additional 58 MW of other DG resources, e.g., wind, hydro, or biomass. The following graph shows the geographical distribution of solar PV by VELCO planning zone over the past 15 years.

FIGURE 17 – HISTORICAL SOLAR DG GROWTH



VELCO was also able to produce progressive geographical heat maps of the state's DG installations in three-year increments for the last four iterations of the Vermont Long-Range Transmission Plan. It can be observed that the majority of new installations tend to cluster in similar geographical areas of the state, which is consistent with our assumption used to study the scenario where solar PV distribution remains constant. One reason for this may be that the majority of installations are rooftop residential and commercial installations. These categories of installations tend to be focused around population centers.

FIGURE 18 – SOLAR PV HEAT MAPS



6.3 Hosting capacity analysis

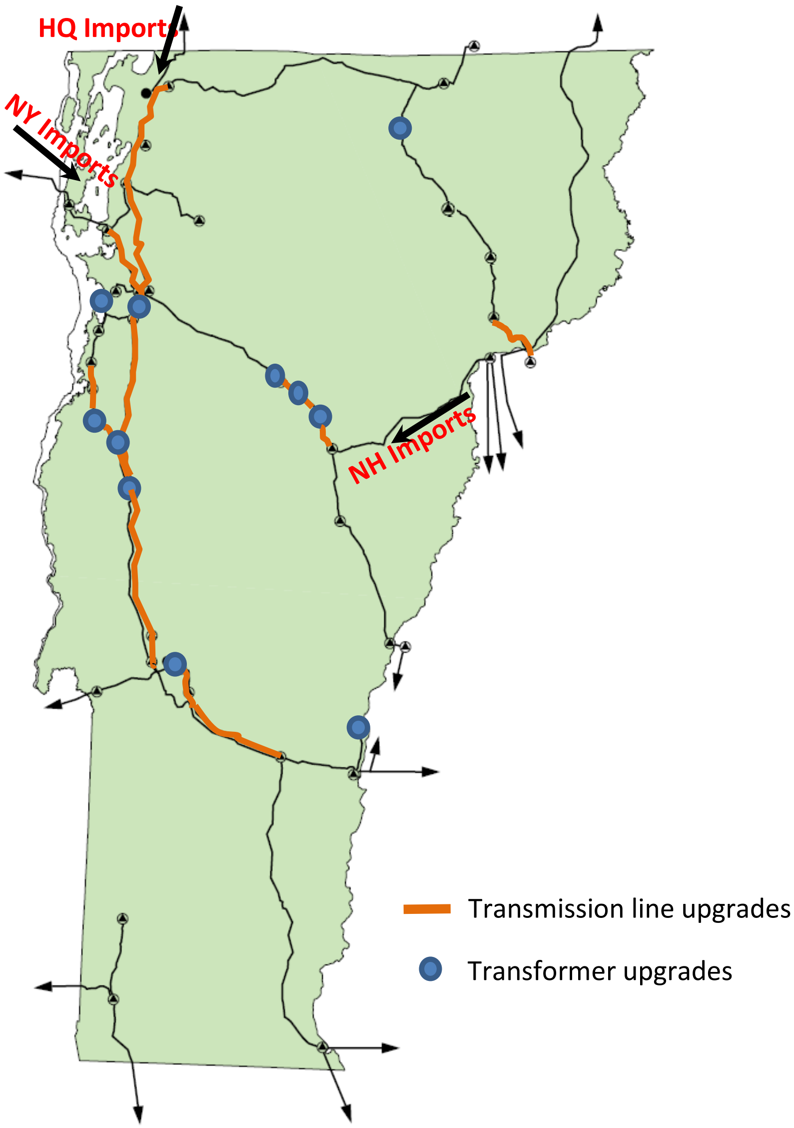
The system was tested at a gross-load level of 650 MW. All gas and diesel units were modeled out of service, and all other renewable resources (hydro, wind, wood, and methane) and the Highgate converter were modeled at full capacity, assuming that existing renewable generation would not be curtailed to accommodate new solar PV generation. System performance was analyzed with the currently installed distributed solar of 485 MW and all other sources of DG totaling about 58 MW. At the current levels of solar PV, some transmission overloads were observed in the Sheffield-Highgate Export Interface (SHEI[21]) and near the Essex substation. These results indicate that with existing DG capacity, the system may not be capable of accommodating all renewable generators operating at full output simultaneously. This does not mean that upgrades are necessarily needed. Our review of actual generation performance indicated that there is some amount of non-coincidence of hydro, wind, solar, and imports, such that the lowest amount tested represents less than one hour of coincidence operation. If overloads did occur in real-time operation, dispatchable generators can be reduced. In addition, future storage or load management can be used if they are properly designed and installed in the right locations. Currently, these mitigating measures are not specifically designed to maximize DG, and they are not coordinated. For example, curtailment of dispatchable generators is an unfortunate outcome as opposed to a planned overbuild of DG that incorporates some amount of economically acceptable curtailment. Most storage and load management programs are currently designed to reduce peak demand. Some storage projects participate in the frequency regulation market. Both of these objectives are currently achieved without explicitly incorporating a DG maximization objective. Further, managing mitigating measures in a way that optimizes various competing objectives is complex, and this complexity is greater when the benefits and costs cut across different entities, as is the case in Vermont.

The system was also tested at several DG levels up to 1,300 MW to examine the impact that may be seen by a predicted doubling in-state renewable generation requirements from 10% to 20% of electric energy sales. The Plan did not specifically test the impacts of Bill H.289 because the analysis was conducted before the details were known. Therefore, the specifics were not modeled, and the results cannot be characterized as reflecting system impacts that would be caused by Bill H.289. Rather, the analysis sought to indicate how the system would be affected if the requirements were simply doubled and nearly all the new generators were solar PV with a 0.14 capacity factor.

Distribution transformer ratings were taken into account, and the Plattsburgh-Sand Bar tie line was modeled at 50 MW of import to Vermont. With additional DG on the system, several transmission facilities were found to be affected. At solar DG installations of 1,300 MW, numerous subtransmission lines, 11 transmission to subtransmission transformers, and approximately 156 miles of transmission lines overloaded. We also observed high voltages across the state, primarily on subtransmission facilities, and a voltage sag at the New Haven 345 kV substation. Below is an illustration of the transmission and substation facilities that would be affected at a 1,300 MW DG level with additional flows to neighboring states through our tie lines.

[21] Additional information can be found at https://www.vermontspc.com/grid-planning/sheffield-highgate-export-interface.

FIGURE 19 – LOCATION OF TRANSMISSION CONSTRAINTS AS A RESULT OF HIGH SOLAR PV



When capacity limits are reached on the distribution system, developers are responsible for funding upgrades that address distribution system concerns. When upgrade costs are beyond a level that can be supported by developers, project development at that location stops. However, since interconnection studies for small-scale DG do not include transmission system studies, transmission concerns can emerge even if the distribution system is not negatively affected. Below is a table listing transmission system concerns and a second table listing subtransmission system concerns found at varying levels of DG, including rough cost estimates if all of these concerns are addressed with transmission upgrades. These concerns can arise if DG is installed without regard to system constraints, which depend on the location of the installations.

TABLE 8 – TRANSMISSION LINE THERMAL IMPACTS OF HIGH SOLAR PV SCENARIO - (ALL DUs AFFECTED)

Transmission Upgrades (rebuild or replace)	DG MW level at the 1st violation	Number of N-1 violation events	Length (miles)	Estimated Cost ($M)	Affected DUs	Lead DU
GEORGIA VT – IBM/GF_TAP 115	500	14	18	136	All	GMP
SANDBAR-ESSEX 115	500	13	11	94	All	GMP
ESSEX-ESSEX_TAP 115	700	210	0.2	2	All	GMP
ESSEX_TAP-TAFTS CORNER 115	700	236	3	25	All	GMP
WILLISTON-TAFTS CORNER 115	700	250	2	17	All	GMP
ESSEX-IBM /GF_TAP 115	800	5	0.02	0.2	All	GMP
NEW HAVEN-WILLISTON 115	800	41	21	159	All	GMP
FLORENCE-MIDDLEBURY 115	900	5	23	174	All	GMP
BERLIN VT-BARRE 115	1000	35	6	43	All	GMP
BARRE-GRANITE 115	1000	25	6	43	All	GMP
WEST RUTLND-FLORENCE 115	1000	5	5	40	All	GMP
NEW HAVEN-VERGENNES 115	1100	3	7	51	All	GMP
GEORGIA VT-SANDBAR 115	1200	6	9	68	All	GMP
MIDDLESEX-BERLIN VT 115	1200	13	5	37	All	GMP
COOLIDGE-COLD RIVER 115	1200	5	18	139	All	GMP
COLD RIVER-NORTH RUTLND 115	1200	5	6	43	All	GMP
ES_60_VEL-ST JOHNSBURY 115	1300	23	5	38	All	GMP
MIDDLEBURY-NEW HAVEN 115	1300	5	8	58	All	GMP
VERGENNES-N FERRISBURG 115	1300	2	5	41	All	GMP
N FERRISBURG- CHARLOTTE 115	1300	4	4	29	All	GMP

TABLE 9 – TRANSMISSION TRANSFORMERS THERMAL IMPACTS OF HIGH SOLAR PV SCENARIO

Transformer Upgrades	DG MW level at the 1st violation	Number of violation events at 1300 MW DG	Estimated Cost ($M)
IRASBURG 115/46 kV	500	6	13
QUEEN CITY 115/34.5 kV	500	14	17
TAFTS CORNER 115/34.5 kV	600	7	10
BARRE 115/34.5 kV	1000	4	17
WINDSOR 115/46 kV	1200	4	13
MIDDLEBURY 115/46 kV	1200	5	13
NEW HAVEN 345/115 kV	1200	1	21
NEW HAVEN 345/115 kV	1200	1	21
BERLIN VT 115/34.5 kV	1300	1	10
VERGENNES 115/34.5 kV	1300	61	8
NORTH RUTLND 115/46 kV	1300	5	21

TABLE 10 – SUBTRANSMISSION LINE THERMAL IMPACTS OF HIGH SOLAR PV SCENARIO

Upgrade	DG MW level at the 1st violation	Number of violation events at 1300 MW DG	Length (miles)	Estimated Cost ($M)	Affected DUs	Lead DU
GORGE-MCNEIL _TAP 34.5 kV	500	137	2.3	2.3	GMP	GMP
BERLIN VT-MIDDLESEX 34.5 kV		6	5.2	5.2	GMP	GMP
LITTLE RIVER-DUXBURY 34.5 kV		6	3.3	3.3	GMP	GMP
ESSEX-AIRPORT_TAP 34.5 kV		14	1.5	1.5	GMP	GMP
AIRPORT_TAP- TOWNLINE 34.5		14	1.2	1.2	GMP	GMP
TOWNLINE-DIGITAL 34.5 kV		14	0.5	0.5	GMP	GMP
DIGITAL-DORSET 34.5 kV		14	2.8	2.8	GMP	GMP
DORSET-QUEEN CITY 34.5kV		13	2.6	2.6	GMP	GMP
FLORENCE- S MIDLBY JCT 46 kV	700	32	13.5	13.5	GMP	GMP
DIGITAL-TAFTS CORNER 34.5 kV		7	2.8	2.8	GMP	GMP
LEICESTER_TP -S MIDLBY JCT 46		23	0.2	0.2	GMP	GMP
WINDSOR- HIGHBRIDGE 46 kV	900	7	6.0	6.0	GMP	GMP
E PITTSFORD-PITTSFRD VLG 46		8	3.1	3.1	GMP	GMP
W MILTON_TAP-MILTON 34.5 kV		62	2.2	2.2	GMP	GMP
DANVILLE-MARSHFIELD 34.5 kV		26	8.8	8.8	GMP	GMP
W RUTLAND-CASTLETON 46 kV	1000	3	6.7	6.7	GMP	GMP
LEICESTER_TP-LEICESTER 46 kV	1100	153	5.0	5.0	GMP	GMP
EAST FAIRFAX-E FRFX VEC12 34.5 kV		9	2.7	2.7	GMP	GMP
WALDEN_TAP-MARSHFIELD 34.5 kV		19	6.7	6.7	GMP	GMP
NORTH END_TP-BARRE VT 34.5 kV		4	1.0	1.0	GMP	GMP
WEBSTERVILLE-SO BARRE SW 34.5		3	2.3	2.3	GMP	GMP
TAFTSVILLE-WINDSOR V4 46	1200	3	10.6	10.6	GMP	GMP

Upgrade	DG MW level at the 1st violation	Number of violation events at 1300 MW DG	Length (miles)	Estimated Cost ($M)	Affected DUs	Lead DU
BALLARD ROAD- CLARK FALL_T 34.5		4	4.3	4.3	GMP	GMP
HARDWICK-WALDEN_TAP 34.5		14	4.1	4.1	GMP	GMP
MONTPELIER-BERLIN VT 34.5		4	2.3	2.3	GMP	GMP
NORTH END_TP-BERLIN VT 34.5		4	2.2	2.2	GMP	GMP
RYEGATE-RYEGATE NEP 34.5		33	2.0	2.0	GMP	GMP
SANDROAD2- ESSEX 19 34.5		6	3.4	3.4	GMP	GMP
QUECHEE_TAP-TAFTSVILLE 46	1300	4	3.4	3.4	GMP	GMP
PITTSFRD VLG -OTTER VALLEY 46		5	5.6	5.6	GMP	GMP
HYDEVILLE-BLISSVILLE 46		2	2.1	2.1	GMP	GMP
HYDEVILLE- CASTLETON 46		3	3.7	3.7	GMP	GMP
EAST FAIRFAX-VEC4_TAP 34.5		11	6.9	6.9	GMP	GMP
MONTPELIER- MNTNVIEW_TAP 34.5		1	2.5	2.5	GMP	GMP
MONTPELIER-E MONTPLRWEC 34.5		7	4.3	4.3	GMP	GMP
SOUTH END_TP- BARRE VT 34.5		3	1.5	1.5	GMP	GMP
MIDDLESEX-MRTWN GEN_TP 34.5		2	2.2	2.2	GMP	GMP

These upgrades could be avoided in part with storage, load management, Grid-optimized locations, and generation curtailment. Regardless of the solution, it is not without cost, and this cost will be borne by generation developers and Vermont customers, or existing and future generators in the case of curtailments. Storage is currently several times more costly than transmission, but some of this storage cost can be recouped by participating in wholesale markets. We should also recognize that battery storage, which is currently the preferred technology, is a limited-energy device. During times of excess generation, storage devices are charged, which would reduce system flows, but the storage device has to release the stored energy into the system so that it can be ready for the next excess energy event. It is likely that the chosen solution will be a combination of transmission upgrades and non-transmission upgrades that will require careful orchestration to ensure that the issue is adequately addressed at all times.

Selecting the preferred solution will not only depend on the cost of the competing solutions but also whether they match the problem being addressed. The tables in the previous page list concerns that may need to be addressed, the DG level at which the first system concern arises, and the number of system outages that would cause the concern. These attributes can help determine whether an operational or generation curtailment solution is a viable solution. Currently, curtailments affect those generators that participate in the markets, but some entities have suggested that small-scale DG could be curtailed as well. For example, if a system concern occurs at a DG level of 600 MW as a result of a transformer outage, then allowing DG to grow to 650 MW without a transmission solution may be acceptable. Generation curtailment or storage may be appropriate depending on the particular situation. If a system concern occurs with no outages, it may be more difficult to select generation curtailment or storage as the preferred solution. Whether the system concern is local or regional can also affect the solution. If the concern is regional, the nature and the location of the solution matter. For example, if the concern is on a transmission line in the central part of the system, then a storage solution in the northern part of the system may be more appropriate than one that is close to the affected line. At this stage of the analysis, there is not enough information to preselect the preferred solution.

6.4 Hosting Capacity Sensitivity Analysis

6.4.1 Optimized solar PV Distribution

The thermal impact tables above show that high levels of DG can result in system constraints assuming high coincident energy production from renewable market resources, Highgate HVDC imports, and Plattsburgh to Sandbar imports. With additional solar PV growth modeled, no other adjustments were made to existing traditional market participant generation resources to make room for the additional DG. The 2018, 2021, and 2024 long-range Plans also presented a DG geographical distribution that would minimize system impacts while DG penetration is maximized by allocating DG to the areas with capacity to accommodate it. This was achieved by allowing overloads of no more than 5% over applicable equipment ratings and assuming no future FERC-jurisdictional generation projects would connect to the system. In the 2021 study, FERC jurisdictional generation projects were studied and found to offset allowable DG installations at nearly 1:1 tradeoff.

The 2018 optimized analysis yielded a hosting capacity of 1058 MW solar DG. The 2021 optimized analysis led to a result of 996 MW of solar DG, and the 2024 optimized study led to a total of 1057 MW solar DG without causing any additional subtransmission or transmission level constraints. The study assumptions and optimized locations of solar PV have changed slightly with each iteration of the study. The 2021 study, for instance, used a gross load of almost 100 MW lower than the 2018 or 2024 studies. Across the three iterations, accounting for gross loads, the amount of solar PV accommodated in the optimized system is similar, while the distribution of that solar PV changes minimally in each iteration. Some variables that impact the optimized distribution could be ongoing subtransmission and transmission system upgrades, improved and updated DG modeling, changing load distributions, and/or various valid parallel solutions. The optimized distribution analysis was updated in this Plan using a new analysis tool that allowed us to fine tune the results with a little more precision.

The 2024 Plan also analyzed an optimized distribution of solar PV considering only transmission limitations, while ignoring subtransmission constraints. The study resulted in a total of 1,175 MW of solar PV hosting capacity, or about 123 MW more than the amount achieved while considering subtransmission facility constraints.

Solar PV was allocated such that distribution transformer ratings would not be exceeded, and it was found that, although this could limit DG at individual distribution substations and reduce distribution upgrade costs, it had a marginal effect on zonal hosting capacity.

The table below shows the modeling assumptions of load and DG derived by the optimized solar PV locations. The currently installed capacity was also updated this year with input from the Department and the distribution utilities and was the starting point for modeling all of the solar scenarios. The table shows that the Newport, St Albans and BED regions have surpassed the 2021 optimized allocations. This is not necessarily a concern because system concerns arise from the aggregate effect of several zones. Increasing DG in one zone would reduce the maximum amount in another zone in order to remain below the system capacity. The 2024 study has found similar conclusions for where DG can be best accommodated by the existing transmission and subtransmission systems.

Table 11 – Optimized solar PV distribution by load zone

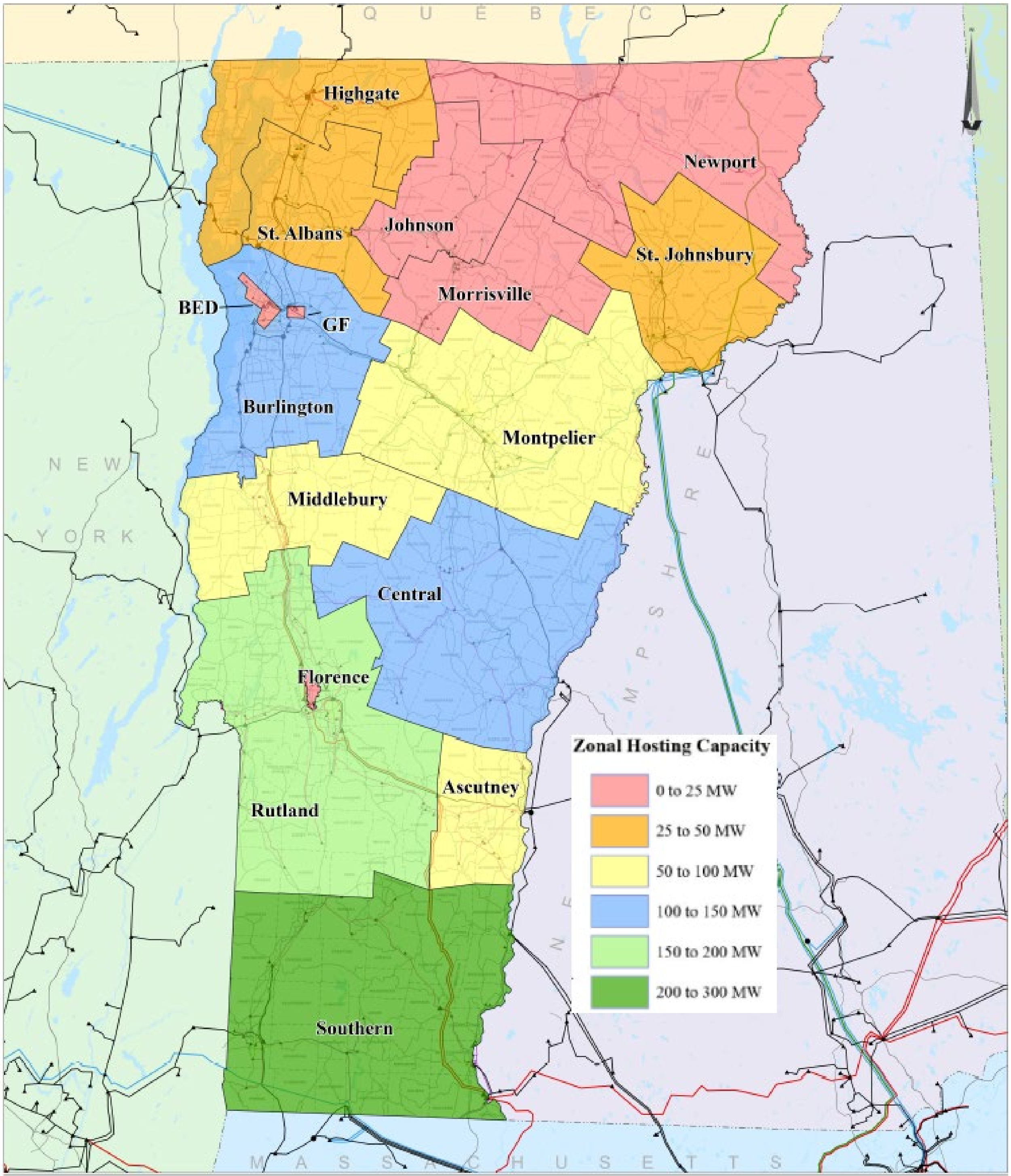
Zone names	Gross loads[1] (MW)	Installed Solar PV as of 2023[2] (MW)	2021 Optimized solar PV distribution (MW)	2024 Optimized Solar PV Distribution Transmission Only (MW)	2024 Optimized Solar PV Distribution Subtransmission Included (MW)	Resulting Loads Net[4] of Optimized PV Distribution (MW)
Newport	25	11	5	49	25	0
Highgate	22	16	20	36	39	-17
St Albans	43	43	40	43	40	3
Johnson	5	7	20	7	7	-2
Morrisville	17	23	25	23	23	-6
Montpelier	60	44	77	126	75	-15
St. Johnsbury	20	18	30	50	51	-31
BED	34	9	8	9	9	25
Burlington/GF	134	93	126	99	97	37
Middlebury	25	33	50	67	61	-36
Central	50	51	99	142	139	-89
Florence	18	0	20	0	2	16
Rutland	64	60	152	164	154	-90
Ascutney	40	25	73	89	81	-41
Southern	82	54	252	271	254	-172
Total	639	487	996[(3)]	1175[(3)]	1057[(3)]	-418

1 Expected midday gross load, i.e. reconstituted or without the solar PV effect, without transmission losses – 12 MW of loads were also modeled as generation station service load
2 DG survey results include units installed as of July 31, 2023
3 Optimized distribution values are totals, i.e. not incremental over existing DG, and include other existing mixed DG resources within the zonal totals
4 Net loads are a proxy for the amount of excess DG that will flow on the transmission system, not counting flows from other generators and imports

The map that follows depicts the regional boundaries that were studied and shows the most appropriate regional allocations of solar PV to avoid transmission and subtransmission upgrades. The map shows how resources are more easily accommodated in the southern regions and more difficult to accommodate in the northern regions. Distribution utilities have created maps to facilitate generation project siting with respect to available distribution capacity.[22]

[22] The BED map can be found at this link, and on the BED website. The GMP map can be found at this link, and on the GMP website. The VEC map can be found at this link, and on the VEC website.

FIGURE 20 – SOLAR PV DISTRIBUTION OPTIMIZED BASED ON EXISTING TRANSMISSION AND SUBTRANSMISSION CAPACITY



The following two tables show the same solar PV allocations from the above optimized distribution scenario. The installed solar PV is totaled and compared against the optimized solar distribution allocated by each distribution utility and by each Regional Planning Commission, respectively, to allow each entity to see how these totals compare with current entity-specific initiatives. The total figures may not be exact due to rounding. In the second table, some of the RPC targets exceed the optimized totals. This may simply mean that a lower amount of solar PV can be accommodated in the other RPCs.

Table 12 – Optimized solar PV distribution by Utility

UTILITY	Installed solar PV as of 2023[1] (MW)	Additional solar PV (MW)	Optimized solar PV distribution (MW)
BED	**9**	**0**	**9**
GMP	**396**	**525**	**921**
Hyde Park	**1**	**0**	**1**
VEC	**41**	**34**	**75**
VPPSA	**25**	**7**	**32**
WEC	**10**	**4**	**15**
STOWE	**3**	**0**	**3**
Total	**487**	**570**	**1057**

TABLE 13 – OPTIMIZED SOLAR PV DISTRIBUTION BY REGIONAL PLANNING COMMISSION

REGIONAL PLANNING COMMISSION	Installed solar PV as of 2023* (MW)	Additional solar PV (MW)	Optimized solar PV distribution (MW)	Regional targets (existing solar + all new renewables) 2050 (MW)	Regional targets (existing solar + all new renewables) 2035 (MW)	Regional targets (existing solar + all new renewables) 2025 (MW)	Notes
Addison (ACRPC)	56	33	89	144	110	72	
Bennington (BCRC)	21	60	81	122	86	49	1
Central Vermont (CVRPC)	51	10	61	343	151	104	2
Chittenden (CCRPC)	89	0	89	394	276	158	3
Lamoille (LCPC)	23	0	23	135	92	49	4
Northeastern (NVDA)	34	64	98	27	23	18	5
Northwest (NRPC)	42	20	62	247	166	88	
Rutland (RRPC)	60	88	148	304	113	50	
Southern Windsor (SWCRPC)	25	60	85	155	81	44	2
Mount Ascutney (MARC)	50	92	142	191	126	67	6
Windham (WRC)	34	144	178	61	46	31	4
Totals	487	570	1057	2121	1269	728	

*Surveyed Data from July 2023.

Notes:

1 2025 and 2035 targets estimated from a target range.
2 Estimated from energy targets. Assumed all new renewables are solar PV at 15% capacity factor.
3 2050 target estimated from a target range. 2025 and 2035 targets estimated by dividing the 2050 target into three parts.
4 2025 and 2035 targets estimated by dividing the 2050 target into three parts.
5 2050 target estimated from the energy target. 2025 and 2035 targets estimated by dividing the 2050 target into three parts.
6 From a TRORC presentation at a September 28, 2015 public meeting.

Below is a table showing the limiting elements of the system that determine the DG capacity of each zone in the optimized distribution. While upgrading these elements may lead to additional capacity beyond what is stated in the optimized distribution, the amount of capacity gained by doing so is presently unclear. It may be that additional limitations would follow soon after one of these limitations were resolved.

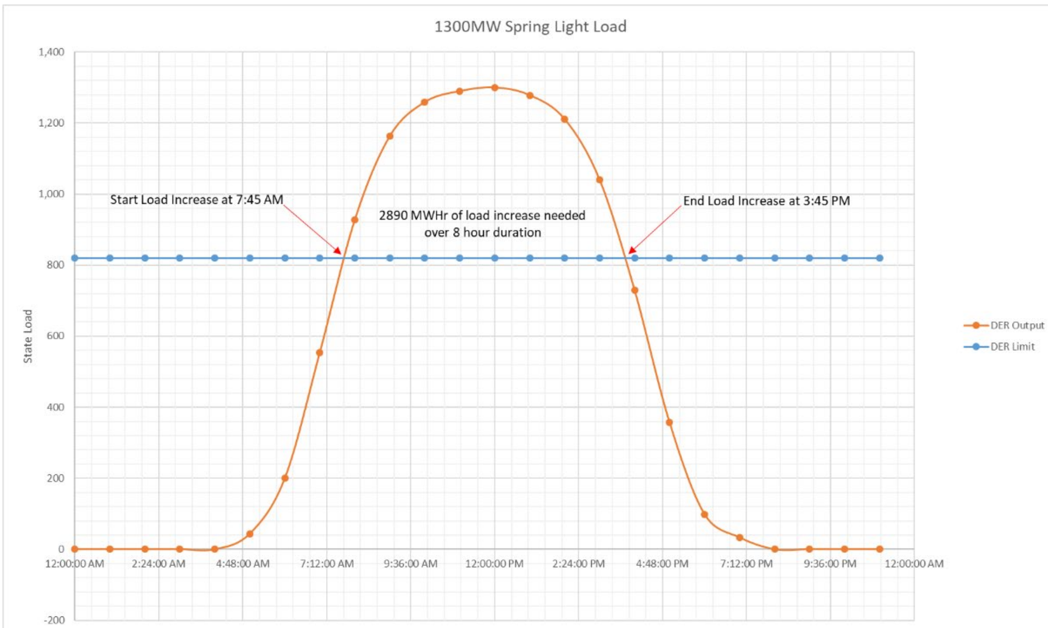
TABLE 14 – LIMITING ELEMENTS OF DG OPTIMIZED DISTRIBUTION BY ZONE

Element Name	Voltage Level	Planning Zones Limited
Irasburg Transformer	115 kV	SHEI, Newport
Sandbar-Essex	115 kV	SHEI, St. Albans
Williston-New Haven	115 kV	Burlington
North Rutland Transformer	115/46 kV	Rutland
Bennington Transformers	115/46 kV	Bennington
Windsor Transformer	115/46	Ascutney
Morrisville-Stowe	34.5 kV	Morrisville
CV Johnson-Morrisville	34.5 kV	Morrisville
East Barnard-Woodstock Tap	46 kV	Central
Dummerston-Newfane	46 kV	Southern
Windsor-Highbridge	46 kV	Ascutney
South Barre-Websterville	34.5 kV	Montpelier

6.4.2 STORAGE AS A MITIGATING STRATEGY

Storage could be used to mitigate thermal and voltage concerns with the historical DG distribution. Storage was modeled where thermal and voltage concerns were located, and the analysis yielded approximately 480 MW of storage capacity across the system to resolve the problems. The maximum duration of excess DG mitigation was estimated at approximately 8 hours and for a total of 2,900 MWh of energy based on the following graph. The solar PV curve was created by overlaying the production curve of a strong solar production day with a peak value of 1,300 MW.

FIGURE 21 – ENERGY ESTIMATE OF AGGREGATE STORAGE OR LOAD CONTROL FOR DG IMPACT MITIGATION



As with any NTA, the duration and frequency of operation matters. The above example represents a worst-case situation where load, generation and transmission import shapes align perfectly to stress the system. In most cases, the amount of excess DG and the duration will be less than indicated above. So, in designing an NTA to address excess DG, one will need to decide whether to design the solution for this worst case or some lower excess amount, and assume some other method, such as curtailment, to address the less likely events. For this assessment to be performed, one needs to understand how these various shapes may align throughout the year, and how that alignment would evolve annually. This type of information will be reviewed as part of a future analysis. In addition, location matters just as much for storage as it does for generation and load. The ideal location for storage to address excessive DG concerns is at a DG plant, in the same way that a DG plant is better located at a load site. The farther the storage is from a constraint, the less effective it will be in addressing it. In fact, if not operated optimally, storage could negatively affect the transmission system in similar ways to excessive DG depending on its location. For example, if storage is located south of a north-to-south constraint, the concerns will be aggravated during the charging cycle of the battery, even if the energy absorption mitigates a local issue. Given this concern, it may be that the operational limitations that would be placed upon a hypothetical storage installation may make the project undesirable to pursue.

The table below shows a single solution for distributing the energy storage devices to resolve constraints created from the 1,300 MW non-optimized solar. There may be alternative and potentially more effective locations for these devices. However, optimizing their placement was not within the scope of this study. These figures are totals, i.e. not incremental to the existing 55 MW of storage.

TABLE 15 – MITIGATION OF 1300 MW DG WITH STORAGE PROJECTS

Storage Locations	Aggregate Amount in MW
BURLINGTON	205
ST ALBANS	65
NEWPORT	55
RUTLAND	35
HIGHGATE	30
MIDDLEBURY	30
ASCUTNEY	15
MONTPELIER	15
MORRISVILLE	15
ST JOHNSBURY	15
Total	**480**

The DG-optimized distribution map also applies to storage when in the discharge mode. Our understanding is that ISO-NE treats a battery's charging load as non-firm load that can be disconnected during system constraints. This would suggest that the battery's discharging load is the critical factor in determining the maximum amount of new storage that can be installed in one of the planning zones noted on the map. Assuming that battery storage operators do not discharge batteries during periods of excess generation, locating storage in generation-constrained areas is not harmful and may be desirable.

Storage solutions can be costly, and often require a stacking of economic benefits to remain an attractive option. In Vermont, these benefits may fall across a wide range of stakeholders, creating an additional barrier to the cost-benefit analysis and overall funding viability of these projects.

6.5 Observations from the results of the solar PV analysis

The solar PV analysis is not intended to lay out a precise prediction of system impacts because several factors can affect system performance. Solar PV distribution is affected by system constraints, environmental, aesthetic, and land use objectives among others. As energy storage becomes increasingly feasible, storage deployment will facilitate solar PV hosting capacity, provided that storage is properly located and designed with sufficient charging capacity.

Location of load and generation matters with respect to the performance of the electric grid. A small amount of additional renewable generation can cause system concerns in certain regions and aggravate generation curtailment. Our study results indicated that the SHEI system concerns may be expanded to other parts of Vermont depending on the amount of additional renewable generation and its location. This solar PV analysis shows that the integration of solar PV targets into the Vermont electric grid is not trivial. If solar PV continues to be developed in the same way as it has in the past, the analysis suggests that solar PV growth will introduce system operating concerns that may require load and generation management, energy storage, and reinforcements to Vermont's transmission, subtransmission, and distribution systems. Our assumption is that solar PV will continue to grow, and this growth will not follow the optimized geographical distribution. The mitigating measures will allow Vermont to maximize the benefits of solar PV and other DG technologies.

The impacts may be mitigated by careful planning of solar PV deployment on a statewide basis. Inverters should be required to follow the requirements of the most recently approved IEEE 1547 standard. Utilities should be able to actively control generation and load, including small-scale generation. An incentive/penalty system could be put in place to encourage generation in areas where sufficient grid capacity exists. Such a system would also need to focus on providing equal access to renewable energy to every customer. The results of this study are a call to renewed focus on careful consideration in planning, technology deployment, and siting of distributed generation.

7 Summary of extreme weather effects on the grid

VELCO recognizes that climate change is producing conditions that are disrupting the electric grid. In response, the Company has commissioned long-term risk assessments of extreme weather hazards in the context of climate change and their potential impact to the electric grid.

7.1 A Warmer and Wetter Vermont

In 2021, VELCO retained Northview Weather LLC to produce the report, "Extreme Weather and Climate Change in Vermont: Implications for the Electric Grid." Forecasting through 2049, the report analyzed seasonal climatic trends across Vermont that indicate, with a high confidence, both warmer and wetter conditions with the likelihood to increase into the future. The most extreme storms appear most likely to occur within the mid-fall season from approximately mid-October to early November when the climatological nexus of tropical moisture and mid-latitude temperature gradients creates significant energy for storm development. Widespread extreme precipitation and resulting flooding also peaks for these mid-fall storms when runoff is more efficient and storms can reap the benefits of tropical moisture.

Additionally, wetter winter storms may increase the severity of ice or wet snow storms. However, the unique meteorological conditions for wet snow and ice of having slow-moving storms with long-lived steady-state temperatures make climatic projections difficult to determine. Overall, the weather risk exposure to the transmission system, the report concludes, results primarily from storms becoming potentially more intense, but not necessarily more frequent.

7.2 Vermont's Wildfire Risk

In addition to the potential for more intense storms, the 2021 report indicated irregular precipitation patterns could potentially lead to more intense drought conditions. In light of this, VELCO retained Disaster Tech, Inc. in 2023 to assess the "Wildfire Risk for VELCO Long-Range Transmission Plan." The assessment concluded that Vermont's current overall wildfire risk is low and that its relatively humid climate with an even distribution of precipitation throughout the year reduces wildfire risks.

However, it is important to note that Vermont has two seasons of enhanced wildfire potential in spring and in late summer to fall. The spring period occurs after the snowmelt, but before the start of the growing season in April to May. This is the driest time of the year and has the highest frequency of red flag warnings (high winds and low relative humidity) issued by the National Weather Service. Because the spring wildfires occur before the growing season, they are more likely to be isolated to the ground and have short flame lengths. These potential fires are often more a nuisance than a true threat and would not cause significant impacts to the transmission system.

Vermont's second fire season may occur during the late summer to fall and is principally forced by the onset of seasonal drought. While trends over the last 20 years have shown an increase in late summer to fall seasonal drought across Vermont, the assessment concludes that there is a low risk of a prolonged drought that would decrease the moisture content of vegetation enough to sustain high-intensity fires that produce rapid spread.

In summary, Vermont's humid climate with evenly spread precipitation reduces the potential for wildfires. While late summer and fall droughts may become more frequent and combine with high wind events, the presence of precipitation with most wind events reduces risk of anomalous rapidly spreading wildfires.

7.3 Planning Future Infrastructure

As VELCO plans facility expansions, upgrades, refurbishments, or modifications, it examines those assets for vulnerability to evolving extreme weather hazards. Newly constructed assets are designed with safe design margins consistent with the latest industry design standards, such as the National Electric Safety Code, that include environmental conditions such as wind speed, ice, and snow loading. These design margins continue to exceed the weather trends projected in the "Extreme Weather and Climate Change in Vermont: Implications for the Electric Grid" report conducted by Northview Weather LLC in 2021.

Additionally, the substation and transmission line asset locations are assessed relative to the most current floodplain data and pertinent regulations. For instance, after the 2011 flooding from Tropical Storm Irene, VELCO conducted a flood mitigation study to identify high-risk assets and put mitigation plans in place. Notably, the state in 2015 adopted the new state Flood Hazard and River Corridor Rule (under 10 V.S.A. § 754) that apply to new VELCO structures. Unfortunately, Vermont experienced another devastating round of flooding in the form of the Great Flood of July 2023. Along with federal and state entities, VELCO is in the process of updating our floodplain assumptions and will revise our buildout plans accordingly. In sum, VELCO has been moving transmission structures and assets away from identified high-risk flooding areas during maintenance and capital project work whenever possible.

VELCO's infrastructure required to maintain transmission system reliability includes a statewide radio system and fiber optic network. The prospect of the potential for climate change-driven higher wind speeds and greater precipitation-induced soil erosion at higher elevations, is prompting revision of that portion of Vermont's building code relevant to the requirements for VELCO's towers, antennae, and buildings. The emerging standard seeks to ensure these assets can withstand higher wind speeds.

VELCO is in the midst of a substantial fiber optic network buildout driven by the reliability need to connect to hundreds of in-state distributed energy resources that in aggregate can substantially impact Vermont's transmission electric grid. As these fiber cables are collocated on transmission and distribution system assets, the greater risk to note here as we plan our system is not the impacts of changing weather, but the growth in the number of miles of cable at risk.

7.4 Vegetation Management

VELCO continues to manage vegetation along its transmission corridor with an eye on the changing conditions caused by climate change, and mindful of emerging state environmental justice requirements. The Transmission Vegetation Management Plan (TVMP) is based on an Integrated Vegetation Management (IVM) program that manages vegetation to promote compatible low-growing vegetation that out-competes tall fast-growing species on a four-year cycle. This approach has been effective at keeping vegetation from growing into minimum vegetation clearance distances and causing outages. VELCO has supplemented this program during the last decade with LiDAR technology that enables the vegetation management staff to identify vegetation that could impact the system at maximum operating conditions and weather conditions such as wind and ice and snow loading.

8 Environmental Justice Act

One of the key objectives of Vermont's Environmental Justice Act, enacted in 2022, is to provide equitable access to environmental benefits, including affordable, clean, renewable energy sources. The Act also seeks to eliminate the historical practice of environmental burdens falling disproportionately on environmental justice focus populations, which the EJA defines as communities that fall below certain income thresholds, that have six percent or more "Persons of Color and Indigenous Peoples," or where "one percent or more of households have limited English proficiency." While not yet in place, the Act's new requirements will be in place within the next few years, and VELCO will seek to contribute to the rules and pay close attention to how these requirements might affect our planning.

In anticipation of the EJA's implementation, this section addresses some of the ways in which VELCO's transmission planning and work currently account for and reflect the EJA's objectives.

VELCO's transmission lines, substations, and other infrastructure provide a number of environmental benefits. To begin, VELCO has created its own Environmental Guidance Manual that focuses on our commitment to environmental sustainability in all of the work we do. This manual includes numerous best management practices to ensure that VELCO's work not only meets, but exceeds, all applicable regulatory requirements to protect the environment.

In addition, all Vermonters need access to electricity, and VELCO and the Vermont distribution utilities provide reliable electricity to electric ratepayers. This service is all the more important as Vermont seeks to implement climate change-related requirements to reduce emissions through electrification of transportation, heating, and cooling. Those emissions reductions depend on Vermont's grid being able to supply reliable electricity to meet Vermont's increased electric load from the replacement of fossil fuels.

Further, by most accounts, Vermont's electric grid is currently one of the cleanest in the nation. VELCO's transmission infrastructure plays a key role in enabling the continued use and expansion of affordable clean renewable energy sources. The EJA explicitly defines "affordable clean renewable energy sources" as environmental benefits. The transmission system allows Vermonters to access the most affordable clean energy available. When VELCO expands or upgrades transmission infrastructure, it expands access to these environmental benefits.

VELCO's vegetation management practices provide another environmental benefit to the areas that host VELCO's transmission infrastructure. VELCO's rights-of-way often enhance biodiversity and wildlife by creating stable early successional habitat that is difficult to find elsewhere. VELCO is an accredited member of the Right-of-Way Stewardship Council and the Nationwide Candidate Conservation Agreement for the Monarch Butterfly on Energy and Transportation Lands. As a result of our sustainable management practices, VELCO's rights-of-way are assets that enhance wildlife habitat.

In addition to expanding access to affordable clean renewable energy sources and enhancing wildlife habitat, VELCO's transmission infrastructure provides multiple financial benefits to Vermonters, including environmental justice focus populations. VELCO's transmission infrastructure is located in over 190 Vermont municipalities, where we provide property-taxed assets that financially benefit both the State's education fund and the hosting towns, villages, and cities. For many towns, VELCO is the largest property taxpayer, even though VELCO’s assets impose little, if any, burden on municipalities. Statewide, VELCO provides annual property tax payments that total around $29 million.

VELCO’s unique-in-the-nation, cooperative-like financial structure also provides valuable benefits to our owners, the Vermont distribution utilities. Those financial benefits, in turn, directly lower costs for ratepayers, thus making electricity more affordable for all Vermonters. This is in line with the EJA’s objective of alleviating disparities that fall disproportionately on low-income populations.

When it comes to potential environmental burdens, VELCO’s planning process prioritizes the Vermont Public Utility Commission’s longstanding policy of encouraging electric utilities to locate infrastructure in existing rights-of-way and substations. This minimizes the chances of potential adverse impacts on Vermonters, including environmental justice focus populations. When we undertake any project, whether within or outside existing rights-of-way, we engage in a substantive, collaborative process of dialogue directly with affected communities and stakeholders. We may earn support or we may not. Our objective, regardless, is to share accessible information, integrate community priorities in project design where possible and minimize community disruption.

For these reasons, VELCO expects that the Vermont Environmental Justice Act will facilitate the siting and improvement of transmission infrastructure projects. VELCO will continue to monitor developments regarding EJA’s implementation, and would welcome improvements to our planning process that increase Vermonters’ equitable access to environmental benefits.