vermont electric power company

VELCO

2021 Vermont Long-Range Transmission Plan

DRAFT

April 12, 2021

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1 Highlights

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

Except for a very a short period of time of flat load, it is expected that summer and winter peak loads will grow at a faster rate compared to previous forecasts, mainly due to the electrification of transportation and heating. Below are the load forecasts studied in the plan. Three scenarios were developed to cover the range of possible outcomes, recognizing that long-term forecasting can be uncertain, particularly since future load growth is greatly influenced by public policy that is difficult to predict. The medium forecasts represent the expected uptick in the adoption of electric vehicles and cold-climate heat pumps. The low forecasts represent a lower growth rate. The high load forecasts represent a much higher adoption rate of electric vehicles and cold-climate heat pumps, which would be on track to meet the Vermont 90% total renewable energy goal by 2050. These forecasts also reflect the effects of energy efficiency and the fact that solar PV generation does not produce any energy at the summer and winter peak hours due to the timing of peak after dark.

	Low forecast scenario		**Medium forecast scenario**		**High forecast scenario**		**All-time peak (year)**	**Historical 5-yr average**
Season	2030	2040	2030	2040	2030	2040		
Summer	1071 MW	1185 MW	1119 MW	1294 MW	1189 MW	1430 MW	1118 MW (2006)	950 MW
Winter	1135 MW	1292 MW	1219 MW	1499 MW	1342 MW	1774 MW	1086 MW (2004/05)	970 MW

Vermont has experienced high load growth in the past, but historical peak load growth has not been as high as that shown in the winter high load forecast. In the medium forecasts, the summer and winter growth rates are 1.3% and 2.1%, respectively. In the high forecasts, the summer and winter growth rates are 1.9% and 3.0%, respectively. The highest historical growth rate occurred from 1993 to 2006, where the summer peak load increased from 818.9 MW to 1118 MW, a 2.42% growth rate over a 13-year period. In the first 8 years of that period, the growth was closer 2.6%. If we compare the total load increase over a thirteen-year period, loads are forecast to grow by 500 MW in the winter high forecast scenario compared to 300 MW in the historical summer growth period. While this level of load growth is unprecedented, we can serve or manage that load successfully provided we coordinate our planning efforts and implement the preferred solutions in a timely manner.

The transmission system has sufficient capacity to serve expected future demand for the first ten years of the twenty-year planning horizon.

VELCO analyzed the system using a methodology consistent with regional and federal standards. In very simple terms, 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. Some transmission facilities were negatively affected due to increased loads, but these concerns were addressed by re-adjusting electric power flows from New York, without exceeding the capacity of the New York system. As the Vermont peak demand continues to grow, and if non-transmission alternatives are not utilized, we anticipate that these flow adjustments will no longer be effective, and grid reinforcement will be required.

At the predominantly bulk level, which consists of delivery points to the distribution utility subsystems, analysis of the medium forecast identified several conditions where transformers and subtransmission lines would need to be disconnected to mitigate local concerns caused by transmission outages. In some cases, these operating actions resulted in load shedding less than the threshold that would allow regional funding of a transmission project based on current New England system planning rules. VELCO will discuss the need to address some of the most severe deficiencies with the distribution utilities. In some cases, local funding may be appropriate and necessary on the basis of unacceptable risk.

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.

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

Since it was expected that the system would fail to meet reliability criteria in the 20-year horizon under the high load forecast, analysis of this scenario was conducted assuming that 75 percent of the EV load could be disconnected for a number of hours during peak periods, per distribution utility input. With this non-transmission alternative maintaining winter loads below 1470 MW and summer loads below 1210 MW, significant transmission upgrades were successfully eliminated. Load management will be necessary, and can be effective if properly designed. These measures will continue to include direct utility control of some loads, as with EV load disconnection. Historical data suggest that reconnecting EV load can result in very high load levels due to a phenomenon called snapback effect or cold load pickup. This suggests that static rate design may not be the right approach going forward. It may also be necessary to utilize a hybrid solution involving storage, load shifting, grid reinforcements, and other measures.

Careful coordinated state wide planning is required to successfully integrate future distributed generation and storage without significant grid reinforcements

Vermont public policies have been very successful at encouraging investment in small-scale distributed generation, which has been primarily solar PV. Based on data provided by the distribution utilities to ISO-NE, 400 MW of solar PV has been installed as of December 2020. This is in addition to approximately 63 MW of other distributed generation (DG) technologies. 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 administrator of the markets. Our analyses have found that transmission capacity can 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 regard to transmission system impacts. If solar PV continues to be deployed without regard to transmission system capacity, solar PV growth contemplated as part of the current Vermont renewable energy standard (RES) and amounts beyond current targets will stress the transmission 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 in such a way as to decelerate DG installations in areas where transmission capacity is limited. The optimized geographical distribution is illustrated on page

43, and it shows that transmission constraints can be minimized and significant transmission upgrades avoided by installing DG without exceeding any of the zonal limits shown on page 43.

- Vermont can also elect to curtail generation, but the financial and technical challenges need to be understood and addressed. Again, thoughtful siting of DG, following the optimized DG distribution map, will 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 is helpful at minimizing system constraints caused by excess generation at certain times of the day.

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. Studies should be conducted to evaluate system impacts of storage projects, as is done for DG and large loads. 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.

Transmission will continue to be essential as we increase clean 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 (DG) is overwhelmingly solar PV, which typically produces energy in the middle of the day from 7AM to 7PM. Because of this generation pattern, the Vermont summer peak demand has moved after dark, and there is no incremental benefit from additional solar PV with respect to serving peak demand if solar PV is not paired with storage designed to provide a significant duration of energy. On cloudy days, or when covered with snow during several days in the winter, solar PV production is very low. On the energy consumption side, the electrification of heating and transportation is increasing demand early in the morning and early in the evening, 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, which imports the energy. To date, Vermont has added more than 400 MW of solar PV generation, which increases the total amount of in-state generation to nearly 100 percent of the Vermont peak demand. Even with this large amount of generation, Vermont imports energy 100 percent of the time. In 2020, where loads were unusually low due to Covid-19 effects, imports were as low as about 15 MW in April, and as high as about 855 MW in July. As solar PV continues to be added to meet the current renewable energy target of 10% of energy sales, Vermont will eventually export energy for a few hours during springtime. In effect, the rest of New England will serve as storage for the excess Vermont solar PV energy by way of the transmission system. Transmission is the means by which Vermont imports energy from neighboring states or will export energy during springtime. In essence, Vermont's environmental sustainability goals are enabled by a reliable transmission system.

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

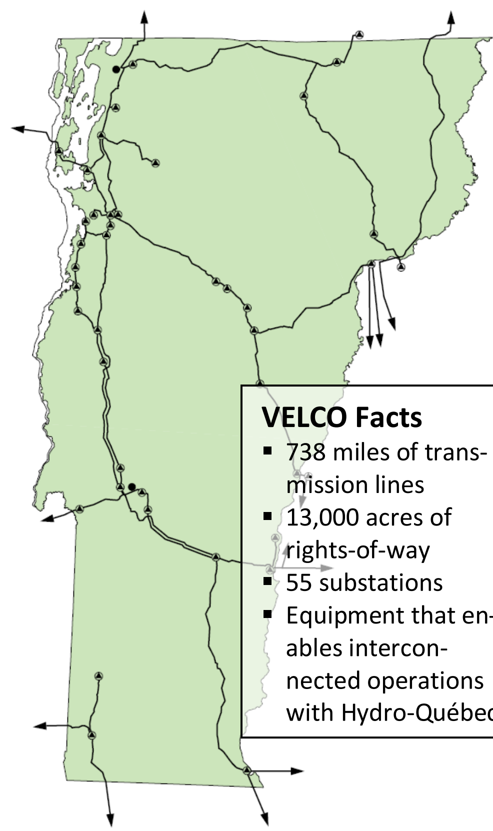
In this plan, we have recommended load management, which is sometimes referred to as load flexibility. Storage clearly has a role to play if designed, operated and located properly, and if cost challenges are addressed. We have also recommended that DG and other distributed resources, such as storage, be properly located to not exacerbate or create transmission constraints. Currently, there is no entity or group tasked to design and implement these solutions. Without additional collaboration and continued innovation, Vermont's electric grid will not be able to fulfill the requirements of current state statutes and policies.

2 Introduction

Vermont law and Vermont Public Utility Commission (PUC) order 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 people—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 generation and load management, may contribute to meeting electric system needs at the lowest possible cost.

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.

VELCO TRANSMISSION LINES AND TIES TO NEIGHBORING STATES AND CANADA



VELCO Facts

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

The 2021 Vermont Long-Range Transmission Plan is the fifth three-year update of the Vermont 20-year transmission plan, originally published in 2006 and updated in 2009, 2012, 2015 and 2018. 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 continually refined its regional planning process, and added staff, as it 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 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 the FERC through its 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, and does not share modeling details such as the basis for the maximum allowed generation outage modeled in power flow simulation cases. 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 (needed within three years of the conclusion of the study).

VELCO completed an annual NERC planning assessment in 2019 as required by the NERC TPL-001-4[1] planning standard. The NERC planning assessment was based on ISO-NE 2019 short circuit and steady state studies, and a VELCO 2016 stability study. ISO-NE has not updated the Vermont Needs and Solutions studies since 2014. Normally, the long-range plan would utilize the results on the most recent ISO-NE Vermont studies 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 because they utilized a load forecast that had not yet considered increased loads due to the electrification of heating and transportation. ISO-NE has started to forecast these loads last year, and ISO-NE has not yet updated all studies with these new electrification loads, which changed the Vermont load forecast from a declining load to an increasing load. Further, previous ISO-NE studies assumed that Vermont's summer peak loads were coincident with the New England peaks. This assumption resulted in modeling excessive levels of solar PV generation. With the currently installed solar PV amount, summer peak production would be assumed to be approximately 100 MW at the ISO-NE summer peak hour.

In reality, due to solar PV delaying the timing of the summer peak, Vermont's summer peak has occurred after dark for several years, and historical data show that solar PV production at the Vermont summer peak hour has been nearly 0 MW, and this will continue in the future as solar PV continues to grow. Finally, ISO-NE does not study winter peak conditions because New England is summer peaking. As a result of very high solar PV growth and expected growth in electric vehicles and cold climate heat pumps, it is anticipated that Vermont will return to being a consistent winter peaking state within five years. 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 Plan because only those system concerns categorized as regional can be addressed by transmission upgrades that are funded regionally based on load ratio share, and Vermont's load share is approximately four percent 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 somewhat out of synchronism, and this can be seen in the load forecasts utilized in these studies. VELCO conducted analysis beyond NERC planning standard's 10-year horizon, analyzed the sub-transmission system[2], included the effects of renewable energy programs and budgeted energy efficiency, and considered non-transmission alternatives as appropriate, all consistent with applicable Vermont policy.

The 2021 plan acknowledges a profound transformation happening on the electric grid. Many changes that are underway or on the horizon will challenge reliable operation of the system as traditionally designed and operated, and provide promising opportunities for new utility models and a more diverse grid. Key factors in the current transformation include retirement of traditional, base load generation,

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[1] TPL-001-4 establishes transmission system planning performance requirements for the bulk electric system (BES). http://www.nerc.com/files/tpl-001-4.pdf

[2] 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.

significant increase in distributed renewable resources, investment in demand-side resources such as energy efficiency, demand response, storage and load flexibility, and the impact of technological trends, such as heat pumps and electric vehicles. These trends have been reflected in the underlying load forecast for the 2021 plan. The plan includes narrative discussion of those trends that cannot yet be quantified with confidence.

Beginning on page 30, this plan shows the reliability needs on Vermont's high-voltage, bulk electric system[3]. Predominantly bulk system issues and sub-system issues follow on page 33. 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. Finally, the plan discusses the review of a base solar PV forecast and a high solar PV scenario that will hopefully facilitate the statewide coordination of solar PV development.

3 Issues addressed since the 2018 plan

The 2018 plan[4] did not identify any major bulk system reliability concerns or predominantly bulk reliability concerns requiring mitigation. The load forecast utilized in the 2018 plan showed lower peak demand than the 2015 plan forecast, particularly during the first ten years of the 20-year planning horizon. The plan identified several subsystem issues to be further investigated by the distribution utilities. These subsystem issues can be found on pages 30 and 31 of the 2018 plan.

Other reliability issues were predicted to occur beyond the 15-year timeframe based on the 2017 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.

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

[4] https://www.velco.com/assets/documents/2018%20LRTP%20Final%20_asfiled.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, or load. In areas where demand is greater than locally available supply, the electrical network must be robust enough to accommodate power imports from outside 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[5] 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[6], NPCC[7], 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, while the regional peak hour continues to occur at 5PM or 6 PM. Sometimes, Vermont and the region can peak on a totally 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.

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

[6] NERC is the North American Electric Reliability Corporation, which is designated by the Federal Energy Regulatory Commission and Canadian authorities as the electric reliability organization for North America.

[7] NPCC is the Northeast Power Coordinating Council, which is delegated authority by NERC to set regional reliability standards, and conduct monitoring and enforcement of compliance.

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).
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, such as switching in or out certain elements, resetting inter-regional tie flows where that ability exists, and 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.

4.2 Funding for bulk system reliability solutions

Because 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 four percent of the cost based on its share of New England load. Likewise, Vermont pays four percent of reliability upgrades elsewhere in New England. Facilities subject to regional cost sharing are called Pool Transmission Facilities or PTF. Most of the load growth related transmission reinforcement needs discussed in Vermont's plans would likely be eligible for PTF treatment. Transmission upgrades needed to support generation growth are not eligible for PTF treatment, and are funded by generation project developers.

Regional sharing of funding for transmission projects has been present in New England for more than a decade. 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[8] 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.

[8] Recently, the northern New England zone has cleared at a lower capacity price, which means that new capacity in Vermont and the rest of northern New England has less value than in other areas of the region. While a lower capacity price is good for the customer, Vermont capacity prices will likely attract fewer generation projects. It is also likely that lower capacity prices will increase the possibility that existing Vermont thermal generators will retire in the physical sense. Both of these effects will put additional stress of the transmission grid due to load growth.

4.3 A note about the 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 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 utilized. This report reflects VELCO's 20-year analysis; however, the main focus is on the 10-year period through 2030. 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 with the Vermont System planning Committee (VSPC).[9]

4.4 Limitations in the scope of the plan

The 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[10]. 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 obligations to maintaining 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 transmission plan requirements are not meant to include those asset condition or routine projects that are undertaken to maintain existing infrastructure in acceptable working condition. Sometimes these 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 the plan 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 (NTA) project screening process. The formal NTA screening tool employed in this process[11] "screens out" projects that are deemed "impracticable" for non-transmission alternatives because they are specifically focused on resolving asset condition concerns. Below are currently known VELCO asset condition assessments that may or may not lead to asset condition projects.

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[9] 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* .

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

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

4.4.1 Selected Substation condition assessments

VELCO's assessment of its substations identifies those elements of the substation requiring repair or replacement. VELCO is currently assessing several substations for necessary refurbishment. The Irasburg, North Rutland, and Florence substations have been assessed, and it has been determined that refurbishments are necessary. The refurbishment projects screened out of a detailed analysis.

4.4.2 Line condition assessments

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

VELCO has assessed the 17-mile K42 line between the Highgate and Georgia substations. The assessment indicated that approximately 50 percent of the poles needed imminent replacement, and that nearly all poles need to be replaced from three to 15 years from now. A plan will be developed to replace the degraded structures.

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 or Vermont section 248 approval, which 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 was modeled at or near zero megawatts (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. Previously completed ISO-NE and VELCO studies have found no system constraints aggravated by the tie flow at 0 MW.

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, and are financed by the project developer, not end-use customers.

Regarding the class of transmission projects called Elective Transmission Upgrades (ETU) that were proposed as a means to import energy from New York or Canada to and through Vermont, VELCO modeled these ETUs and their associated upgrades out of service, because although some of them have been approved by ISO-NE, they are quite uncertain due to the complex economic constraints involved. Two such projects have been withdrawn, and the remaining third project has postponed its in-service date three 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, which tend to handicap 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 ETU projects in question have been evaluated by ISO-NE as a part of their system impact studies, which included a comprehensive assessment of both import and export conditions. VELCO reviewed and provided feedback in these studies, and determined that the study work performed was adequate to ascertain the ETUs impacts to the Vermont transmission system. The system impact studies identified the need for several system upgrades to address system concerns that would arise if the ETUs were constructed.

4.5.2 Generation

All Vermont generators that participate in the 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 base load generators, which are expected to run at or near full capacity nearly every day for hours at a time. The largest Vermont generator is a 65 MW wind plant that would be 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, whose operation approaches that of a base load generator. Other base load plants are rated 20 MW or less and total approximately 30 MW.

ISO-NE has 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 the result of a careful evaluation of overlapping probabilities of generation outages and load levels, and it has been adopted and deployed in ISO-NE's ten-year studies. During the development of this process, ISO-NE predicted this probabilistically based dispatch can be skewed depending on the number and type of generation resources in the study area. ISO-NE's first attempts at utilizing probabilistic dispatch yielded more severe generation outages pre-contingency, and ISO-NE had to modify the probabilistic approach by applying a two-generator outage limit to generators at an individual substation in order to prevent these dispatches from being unreasonable.

ISO-NE has determined that it cannot share the details of the calculation that yields the maximum allowable generation outage due to FERC Order 1000. In response to an information request that VELCO submitted to ISO-NE, the maximum allowable generation outage for Vermont is 78 MW, which corresponds to the outage of the McNeil plant and one of the two Swanton gas turbines (GTs), which means that all of the other 14 Vermont thermal units are expected to run when needed. VELCO believes that this generation outage assumption is too optimistic considering the characteristics of the Vermont thermal generation portfolio. Therefore, VELCO modeled 101 MW of generation out of service, which corresponds to the McNeil plant out of service and approximately one-third of the capacity of the diesel and gas turbines, which could be the Gorge GT, the Rutland GT, one of the two Swanton GTs, and one of the four Essex diesels.

4.5.2.1 The Highgate Converter

The Highgate Converter is the point at which energy flows from Hydro-Québec (HQ) to Vermont's electric grid. The converter can carry the full amount contracted between HQ and Vermont distribution utilities during all hours of the year except periods of high demand that can affect the HQ system. Although the converter can operate at its full 225 MW capacity[12], the converter currently operates slightly below this amount because the current 225 MW contract is located at the US border, not at the converter.

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 in the same way as any other transmission facility.

4.5.2.2 Vermont peaking generation

Thirteen Vermont generators with a nameplate capacity of approximately 145 MW count as peaking resources—generators that are expected to run only during peak load conditions, when demand is near system capacity, or during some form of system emergency. As noted earlier, ISO-NE utilizes a probabilistic approach to determine the maximum allowed generation outage amount. Based on ISO-NE's approach, the McNeil plant and one of these peaking generators would be considered unavailable prior to testing contingencies. ISO-NE assumes that 20 MW out of 145 MW or approximately 14 percent would not start or remain in service during a transmission outage event. This assumption is too optimistic, and VELCO assumed that 30 percent or 43 MW of the peaking units would be out of service in the long-range plan analysis.

The total amount of thermal generation available for dispatch, comprised of the biomass units, McNeil and Ryegate, and the peaking units, is about 225 MW. Utilizing the ISO-NE probabilistic approach, 147 MW of these resources would be modeled in service at the peak hour. A review of 40 seasonal peaks in the last twenty years suggests that the amount of generation running during the peak hour can exceed 144 MW with a probability of 7.5%, whereas the probability of exceeding 122 MW is 20%. The analysis modeled 123 MW in service, and this amount is much higher than the average generation expected to be running during the peak hour, which is 75 MW, the amount that the biomass units generate.

Because ISO-NE does not share the data that is used to calculate the maximum allowed generation outage, we do not know the details that support the ISO-NE threshold outage amount. Beyond the outage statistics (EFORd), one should consider the characteristics of the units involved. In this case, historical performance of the peaking resources would suggest that the peaking units are not expected to run even during extreme peak weather conditions. The probability of all the peaking resources to be at 0 MW is over 52%. If we were to model the expected amount of generation running at the peak hour, the amount of generation would be about 75MW versus the 123 MW amount modeled in the analysis. This larger amount is based on the assumption that most peaking units will come on line when called upon. Based on historical performance, some units will be unavailable to run, or fail to start or trip shortly after starting. Additionally, the peaking resources are not designed to run for many hours. Suppose the outage of concern is a long-duration outage, such as a transformer failure, the peaking resources may be

[12] 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.

able to support the system for a handful 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, as observed in their amount of run time before failure record.

4.5.2.3 Hydro and wind generation

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

4.5.2.4 Small-scale renewable generation

State policy, grant funding, federal tax incentives, 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[13] and the standard offer program[14]—are assuring a market for the output of small-scale renewables. New net metering rules that became effective on July 1, 2017[15], eliminate 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 August 2020, approximately 264 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 2020, approximately 70 MW of standard offer resources were in service, 84 percent of which were solar photovoltaic (PV) generation. Since January 2014, new standard offer installations include 0.4 MW of farm methane, 3.2 MW of hydro, and 41 MW of solar PV accounting for 92 percent 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 utilizes 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 percent 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. Since solar PV effects have shifted the Vermont summer demand peak to after sundown, this analysis assumed that incremental solar PV would contribute 0 MW at

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[13] 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.

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

[15] Rules are available on the PUC's website at http://puc.vermont.gov/about-us/statutes-and-rules/proposed-changes-rule-5100-net-metering

the summer peak hour. Similarly, since winter peaks occur after dark, solar PV also contributes 0 MW at the winter peak hour.

Lastly, in 2015 the Vermont legislature enacted a Renewable Energy Standard (RES) and energy transformation (ET) requirement[16]. The highlights are as follows:

- Total renewable requirement (55 percent by 2017 increasing to 75 percent in 2032), known as Tier 1—includes any vintage and large hydro;
- Distributed generation carve-out (one percent of sales in 2017 increasing to 10 percent in 2032), known as Tier 2; and,
- Energy Transformation Projects (two percent of sales in 2017 increasing to 12 percent in 2032), known as Tier 3—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.

All of the above programs contribute to Vermont's efforts to meet the renewable energy goals set in the 2016 Vermont Comprehensive Energy Plan (CEP). These goals expand upon the statutory goal of 25 percent renewable energy by 2025, and they are noted briefly below.

- Reduce total energy consumption per capita by 15 percent by 2025, and by more than one third by 2050.
- Meet 25 percent of the remaining energy need from renewable sources by 2025, 40 percent by 2035, and 90 percent by 2050.
- Three end-use sector goals for 2025: 10 percent renewable transportation, 30 percent renewable buildings, and 67 percent renewable electric power.

These renewable energy goals serve as important considerations for the 2021 Long-Range Transmission Plan.

4.5.2.5 Proposed generation projects in the ISO-NE interconnection queue

The 2021 analysis takes into account any new generators that have a capacity supply obligation. Conceptual or proposed projects were not considered. 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 the 2018 plan, several generation projects have withdrawn from the ISO-NE generation interconnection queue, most of which consists of solar PV generation. None of these queued generation projects have been installed since 2018.

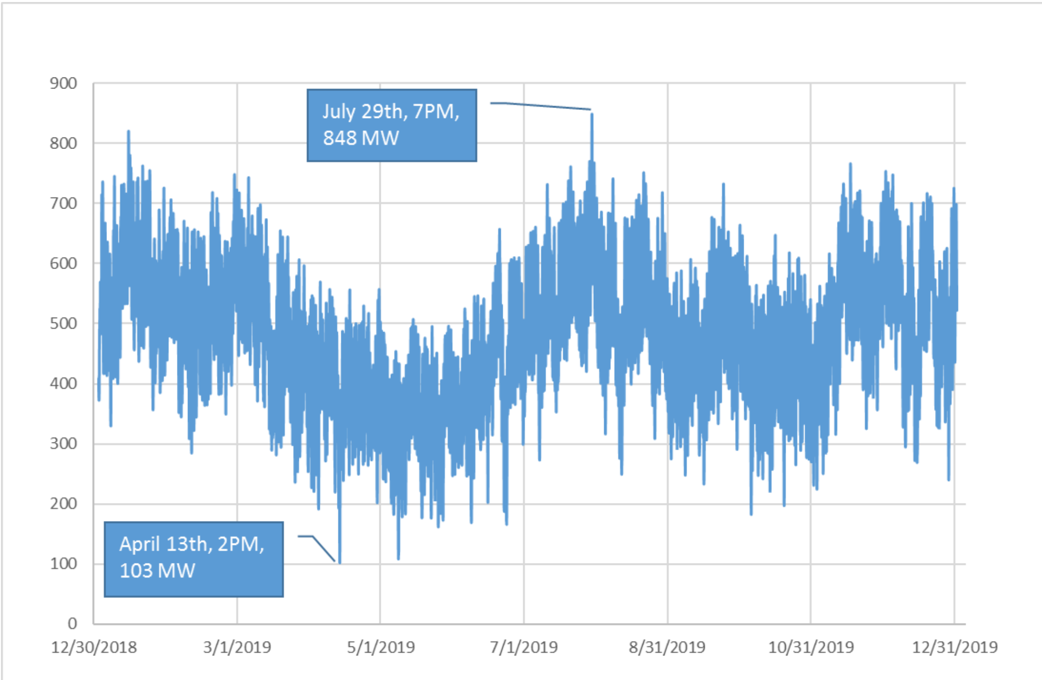
4.5.2.6 Vermont as a net importer

Vermont has roughly 1000 MW of installed generation, including approximately 400 MW of distributed solar PV and 63 MW of other small-scale generation, which accounts for approximately 100 percent of the summer peak load; however, due to the performance characteristics of in-state generation, 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

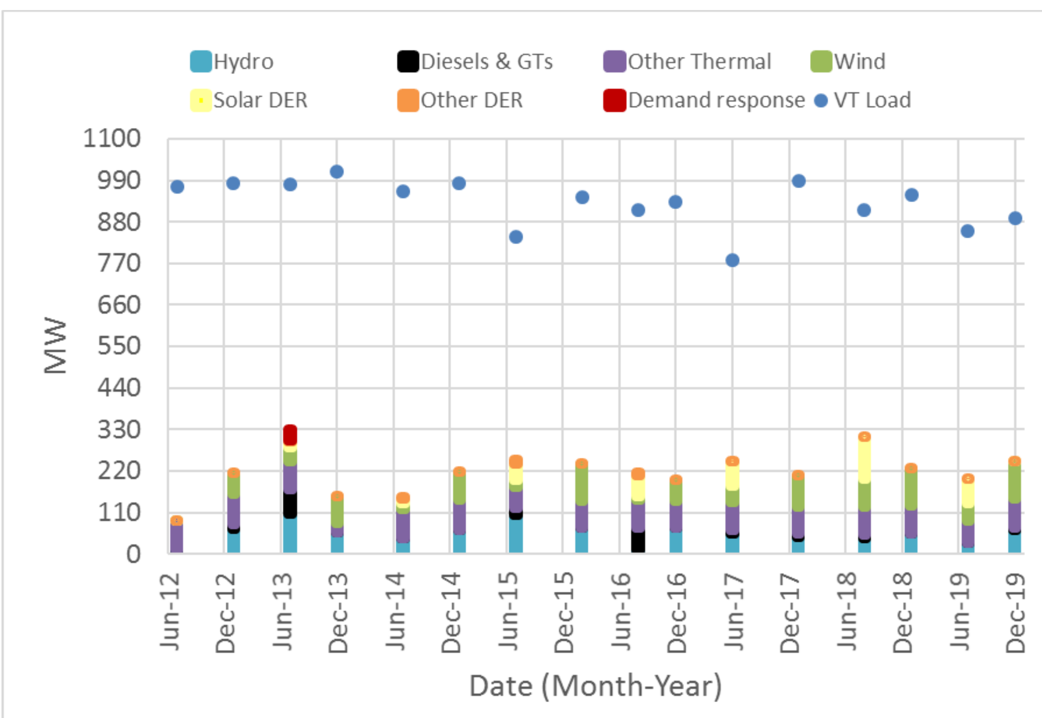
[16] Enacted as Act 56 of the 2015 Vermont General Assembly, codified in Title 30 Subsections 8002-8005 of the Vermont Statutes.

power at 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 are a graph of 2019 import levels, and a graph showing the contribution of internal resources serving Vermont load during the New England peak hour.

Vermont MW imports in 2019



Vermont generation during the New England peak hour



Historical data from the past five summer and winter hours indicate that the transmission system serves anywhere from 75 to 90 percent of the peak load depending on the production of intermittent generation resources at the Vermont non-coincident peak. 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) typically reduce the demand at the distribution level. However, energy efficiency and demand response that have a capacity supply obligation through the ISO-NE forward capacity market are treated like a transmission-connected generator for planning purposes. DERs typically include standard offer, net metering, and utility installed resources that are currently treated as behind-the-meter resources. DERs have reduced demand at the time of the ISO-NE peak from about two MW in 2012 to about 113 MW in 2018, but their contribution has dropped to about 64 MW in 2019 because the ISO-NE summer peak moved from 5PM to 6PM in 2019. 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 21, 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.

4.5.3 FORECASTING DEMAND

The analysis models future electric demand consistent with the results of a load forecast completed in September 2020 by Itron, an energy firm that offers highly specialized expertise in load forecasting, under contract with VELCO. Planning studies for this long-range plan assume peak load conditions that occur during extreme weather conditions also called a “90/10” forecast, meaning there is a 10 percent 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, which the transmission system would serve on a normal sunny day in spring.

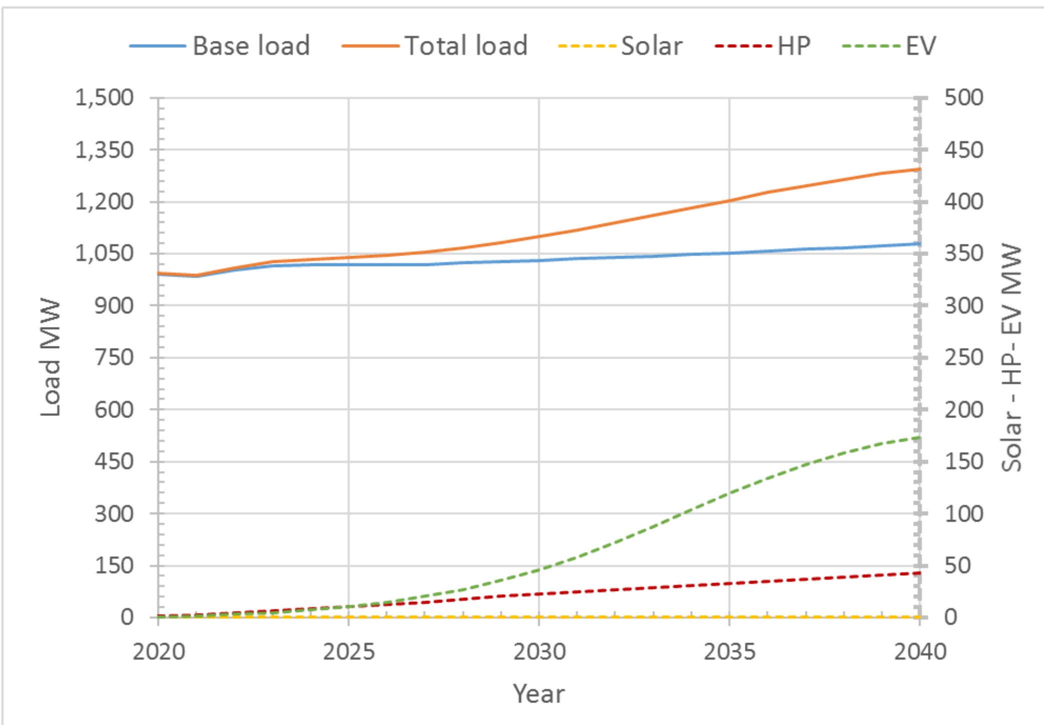
The forecast of future demand for electricity is a critical input in electric system planning. The forecast determines where and when system upgrades may be needed due to inadequate capacity. Predicting future demand relies on assumptions about economic growth, technology, regulation, weather, and many 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 at www.vermontspc.com/2020LoadForecast.

In developing the Vermont forecast, Itron incorporated the latest energy efficiency projection in collaboration with the Vermont Department of Public Service (DPS), the Vermont Energy Investment Corporation (VEIC) and the VSPC, which includes representatives of the distribution utilities, energy efficiency utilities, and the public. Itron employs an end-use model that essentially forecasts each consumption type—e.g., lighting, heating, 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.

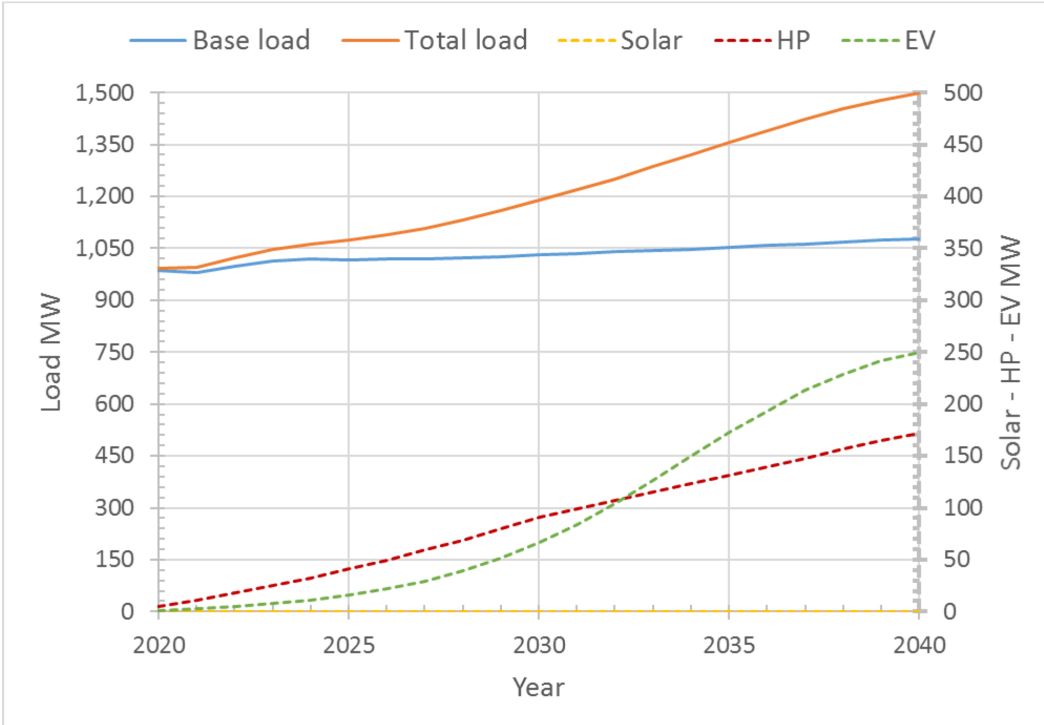
The forecast took into account the near-term effect of the Covid-19 pandemic. The economic forecast underlying the load forecast predicts a significant drop in gross state product (GSP) and employment as a result of the Covid-19 forced economic shutdown, which will roll through 2021. The economy is expected to recover after 2022 with strong economic growth in 2024, but it is not until 2026 that GSP reaches the level prior to the Covid-19 pandemic.

The following graphs depict the twenty-year extreme weather, or 90/10, forecast adjusted for the effects of energy efficiency, demand response, 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 vertical axis on the left of each graph (0 to 1500 MW) applies to the base load forecast (blue line) and the total load forecast (orange line), which is the load the transmission system will be designed to serve. The base load forecast has been adjusted for energy efficiency programs. The total load forecast is the sum of the base forecast and the component forecasts that would either increase or decrease the load depending on the technology. The vertical axis on the right of each graph (0 to 500 MW) applies to the component forecasts representing the projected impact of electric vehicles (EV, green line), heat pumps (HP, red line), and solar PV (yellow line), which is 0 MW because the seasonal peaks occur after dark.

PROJECTED VERMONT SUMMER PEAK LOAD AND ITS COMPONENT FORECASTS



Projected Vermont winter peak load and its component forecasts



While the base forecast is relatively flat, the total forecast predicts sustained load growth mainly driven by electric vehicle growth and cold climate heat pump growth. Even so, the summer peak is not predicted to reach the all-time peak of 1120 MW until 2031. The winter peak grows faster than the summer peak, and is projected to reach the all-time winter peak of 1086 MW in 2026. The load forecast projects total summer peak load levels in 2021, 2031, and 2040 of 988 MW, 1119 MW, and 1294 MW, respectively. The corresponding total winter peak load levels are 994 MW, 1219 MW, and 1499 MW, respectively.

4.5.3.1 Demand response

As can be seen in the above graphs, demand response was not explicitly plotted. Itron did not forecast demand response as there is no mechanism to forecast the demand response beyond the last forward capacity auction. Additionally, demand response varies based on market forces and can easily leave the market at any time. Future demand response was kept constant, following the last forward capacity commitment period. It was assumed that demand response summer capacity would be 26 MW in 2020, 40 MW from 2021 to 2023 based on the latest auction results, and stay constant at 40 MW for the remainder of the planning horizon. Similarly, it was assumed that demand response winter capacity would be 30 MW in 2020, 44 MW from 2021 to 2023, and stay constant at 44 MW for the remainder of the planning horizon.

Beyond the category of demand response with a forward capacity supply obligation, there are several programs and initiatives that seek to control or manage load in Vermont. These load management or load flexibility efforts were not forecasted. However, they were recognized as a resource that would be utilized to address system concerns that may arise. 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, remote control of water heaters, heat pumps, electric vehicle chargers, and HVAC. Currently, several tens of MW 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. To test the value of load management or load flexibility, we utilized an assumption consistent with distribution utilities' experience, which is that 75 percent of the electric vehicle load could be disconnected during the peak hour in the high load forecast sensitivity analysis. EV load was modeled as uncontrolled in the medium forecast analysis.

4.5.3.2 Electric vehicle forecast

The demand associated with EVs is predicted to become a noticeable element of the load in the mid- to long-term. The electric vehicle forecast was developed by VEIC, which provided the number of electric vehicles and associated energy consumption. As of January 2020, there were 3,716 EVs registered in Vermont, which is 2,500 more EVs than in 2016. Presently, EV adoption rates are not growing as fast as would be necessary to meet Vermont's climate goals. VEIC updated the EV forecast based on recent market trends, industry reporting and professional judgement. Recognizing the uncertainties around the effects of Covid-19, state/federal EV incentives, emissions requirements, and EV model availability, particularly larger all-wheel drive vehicles, a range of forecast scenarios were provided. The medium, or expected, forecast assumes that EV growth rate will achieve 60 percent of registered light duty vehicles, or 279,000 vehicles by 2050. The low forecast scenario assumes a 40 percent saturation or 163,000 by 2050, and the high scenario assumes a 90 percent saturation or 418,000 vehicles by 2050. The medium EV forecast shows the EV electrical demand at the summer peak hour will grow from 1 MW in 2020, to 11 MW in 2025, 46 MW in 2030, 119 MW in 2035 and 173 MW in 2040. The winter EV demand is expected to be somewhat higher based on historical EV demand. The corresponding winter demand figures are 1 MW in 2020, to 16 MW in 2025, 66 MW in 2030, 172 MW in 2035 and 250 MW in 2040. These figures assume no load management, such that system concerns can be properly identified. In turn, these system concerns discovered could indicate a need for such load management measures.

Note that the EV forecast is only for light-duty vehicles (passenger cars, sport utility vehicles, and smaller pick-up trucks), which are the vast majority of vehicles. There are approximately 620,000 vehicles (automobiles, buses, trucks, motocycles) in Vermont per the US Department of Transportation https://www.fhwa.dot.gov/policyinformation/statistics/2018/xls/mv7.xlsx, and this forecast focuses on the potential of EVs to replace a portion of the 450,000 light-duty vehicles currently registered. As noted above, we recognize the uncertainties associated with an EV forecast. Incentives play a large role in EV growth rate, but we wonder whether EV technology evolution, particularly as it relates to large vehicles, trucks, buses, and battery chargers, would have a transformative effect on EV adoption. Presumably, if current barriers to EV adoption were to drop sooner rather than later, EV adoption and the resulting electrical demand would grow faster than predicted. This scenario could be tempered if the distribution utilities are able to adequately manage EV charging electrical demand.

4.5.3.3 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.

Efficiency Vermont, with input from the VSPC Load Forecast Subcommittee, developed three scenarios (low, medium, high) of the long-term heat pump forecast. In the medium scenario, Efficiency Vermont expects installations of around 6,000 units per year in the near term, rising to 10,000 units per year by 2028. This forecast is more than twice as large as the previous forecast, but it is supported by field data and Efficiency Vermont's understanding of the Vermont market. The medium heat pump (HP) forecast shows the HP electrical demand at the winter peak hour will grow from 5 MW in 2020, to 41 MW in 2025, 91 MW in 2030, 132 MW in 2035 and 172 MW in 2040.

The ability to cool with the same high-efficiency equipment will tend to be additive to the existing cooling load. The summer HP demand figures are 1 MW in 2020, to 10 MW in 2025, 23 MW in 2030, 33 MW in 2035, and 43 MW in 2040. These winter and summer HP forecasts assume no load management, such that system concerns can be properly identified. In turn, these identified system concerns could indicate a need for such load management measures.

4.5.3.4 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 an explosion of solar PV generation, the predominant technology since 2012, with lesser contributions from wind, hydro, biomass, and methane. Itron utilized 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 phase-out of the investment tax credit and projected slower declines in equipment costs. As of the end of 2019, 361 MW of solar PV had been installed. The forecast projects net metering to grow to 535 MW in 2025, 562 MW in 2030, 578 MW in 2035, and 585 MW in 2040. Standard offer is projected to grow as scheduled from 70 MW in 2019 to 127.5 MW in 2025, and remain at that level through 2040 based on current policies. With the addition of standard offer, the total solar PV forecast increased to 630 MW in 2032, which is less than the amount required to meet 10% of energy sales per the Vermont Renewable Energy Standard. As a result of this deficiency, the forecast was increased to 683 MW in 2032, and continued to increase to 704 MW in 2035, and 733 MW in 2040 to keep pace with the forecast growth of energy.

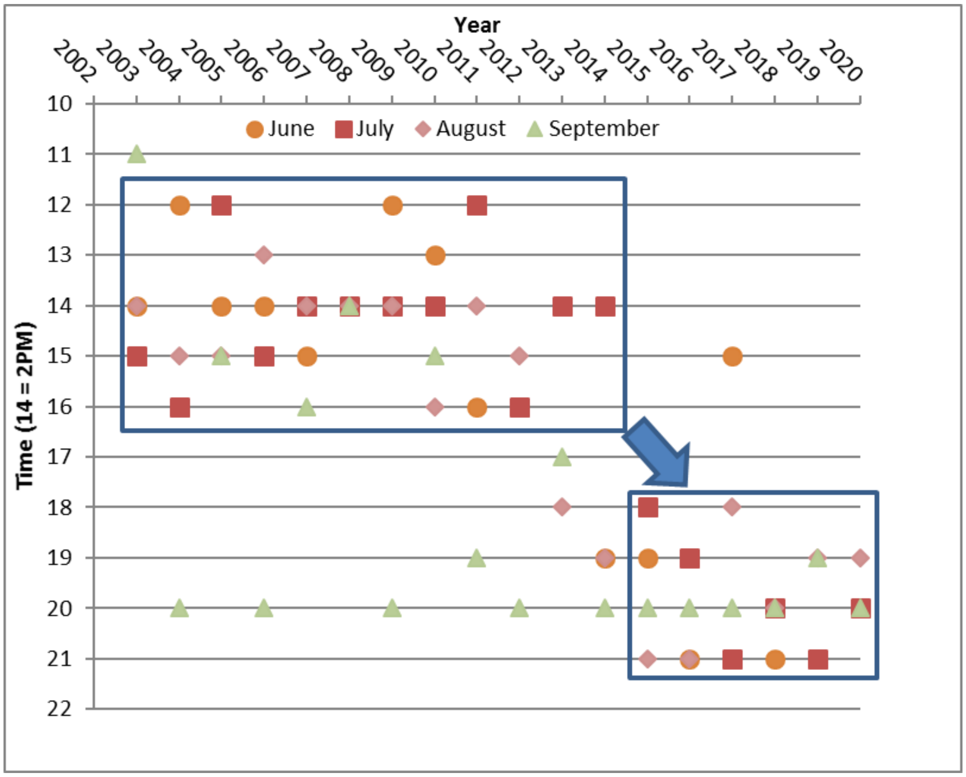
The Itron load forecast indicated that the summer and winter peak net load will occur after dark. Therefore, the contribution of solar PV at the peak hour is predicted to be 0 MW.

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 approximately 960 MW in 2020. However, the annual peak can occur either in summer or winter depending on which of these two seasons experiences the most severe weather.

Small-scale renewable energy has also affected the timing of the peak during the summer months, June to September. The following graph shows the progression of monthly peaks for the summer period. Until recently, peak loads from June to August occurred consistently in the afternoon (2 PM plus or minus two hours). The graph shows that the timing of the monthly peaks has transitioned to later in the evening starting in 2014 where, for the first time, May's peak occurred at 9 PM, June's peak at 7 PM, and August's peak at 7 PM. Only July, typically the month in which the annual peak occurs, did not peak later than 4 PM in 2014, but the July peak has clearly moved to the evening. Since the timing of the summer peak has moved to 8 PM or later, incremental solar PV will no longer have any effect on the summer peak timing or load level. 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.

SUMMER PEAK LOADS ARE OCCURRING IN THE EVENING



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. Small-scale renewable generation is making the curve more concave in the middle of the day. This transformation is relevant to the development of NTAs, such as energy efficiency and generation. An NTA that is proposed to reduce a summer peak will potentially need to be in service in the morning and the evening hours. Renewable energy is not only affecting system planning, it is likely affecting the efficacy, i.e., the coincidence factor, of energy efficiency measures at the time of the peak. For instance, if past measure portfolios were designed to reduce a type of load from noon to 4 PM, new or different measures may be needed that also reduce the load after 4 PM. Renewable energy and energy efficiency may very well work together, where renewable energy reduces daytime loads and energy efficiency reduces nighttime loads.

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 complexity and uncertainty of these factors means the timing of load level predictions is inherently uncertain. 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 at 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 large customers who in the future will be called upon to curtail load based on the energy market rather than system events and conditions as in the past. Last September, FERC issued Order 2222, which allows distributed generation to be aggregated and participate in wholesale markets. The effect of this change is not fully known at this time, but one can assume that the economics and the design and monitoring requirements of distributed generation projects will change, which will in turn affect distributed generation growth.
- 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 current load forecast includes an explicit forecast of electric vehicle load, which increases state load. However, that load increase can vary between 68 MW in the low summer load scenario and 404 MW in the high winter load scenario over the next 20 years. The forecast also includes a projection of high-efficiency heat pump load. This reinforces the belief that 20-year forecasts are likely too uncertain to be the primary basis for electric grid planning.
- Regional uncertainties may affect Vermont as a part of the interconnected grid. Environmental regulations will likely impact New England's generation mix, and ISO-NE has previously projected the retirement of a large amount of New England generation due to market forces and environmental concerns. In fact, the ISO-NE 2019 Regional System Plan reported that more than 5,400 MW of generation and demand-response capacity have retired or will retire by 2022/2023. During the 2018/2019 through 2022/2023 period, over 3,700 MW of generating resources and 2,900 MW of demand resources have been or are expected to be installed. In addition, the ISO-NE Distributed Generation Forecast Working Group projects that over 7,795 MW of

solar PV generation capacity will be installed by 2029. New sources of energy, including imports and elective transmission, albeit regional resources, may affect the performance of the Vermont system, particularly for the period beyond 10 years. ISO-NE is conducting economic studies evaluating electric grid impacts of interconnection scenarios for as much as 8,000 MW of off-shore wind projects. Several import projects, varying in size from 400 MW to 1,200 MW, have been proposed to connect to various locations in Vermont. Only one of those projects remain in the ISO-NE interconnection study queue. The changing generation mix in the US has raised concerns about grid resilience. ISO-NE continues to be concerned about fuel security during winter periods, and has put in place measures to maintain bulk power system reliability through an entire winter. Maintaining reliability is likely to become more challenging, especially if current power system trends continue. The electric grid transformation is of great importance to ISO-NE and other stakeholders, which are currently undertaking a future grid reliability study whose objective is to assess and discuss the future state of the regional power system in light of current state energy and environmental policies. New England stakeholders seek to understand potential impacts on not only electric grid reliability, but also regional markets.

- Recently, renewable energy and small-scale distributed generation have expanded dramatically. Amendments to Vermont statutes enacted in 2012 and 2014 will greatly increase generation developed through Vermont's standard offer and net metering programs over the next decade. The forecast maintains standard offer constant at 127.5 MW beyond 2025, as the program is expected to be fully subscribed as of that date.

- Reliability standards set by NERC continue to evolve in a more prescriptive direction that will further reduce discretion about how to analyze the system and what solutions are compliant with regional and federal regulations. A revision to the planning standard will become effective in 2023, and this standard is expected to continue to evolve and others will be developed in an effort to improve system reliability. For instance, it is reasonable to expect that a new standard or planning process will be developed nationwide and regionally to address grid resilience concerns associated with low likelihood, high consequence natural or man-made events. It has been suggested that climate change is increasing the likelihood of catastrophic events to a point where grid-hardening measures should be considered. In the New England area, the grid resilience discussion is focusing primarily on winter fuel security concerns. VELCO has not identified a specific need to upgrade its transmission facilities to address resilience concerns at this time. However, resilience is one of the considerations in the design of transmission facilities, which can include the location of facilities in relation to FEMA flood levels, equipment height, equipment design specifications, and redundancy. Storage may have a role in maintaining system reliability during outage events.

- 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; heat pumps are allocated based on zonal distribution of electric energy consumption; and demand response is allocated based on ISO-NE bus-level load distribution. 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 DPS prepared a comprehensive report on the deployment of storage on the Vermont grid[17] 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, however, storage is likely 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 ten percent 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, such as what-if analyses and minimax regret optimization[18]. Faced with significant unknowns, a high-load scenario and a high-solar PV scenario were developed to represent two potentially impactful 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.

4.5.5.1 High load forecast scenario

Planners have addressed load forecast uncertainties by preparing a high forecast and a low forecast in order to bound uncertainties. In this case, we do not believe analysis of the low forecast would provide much value because the low load forecast is already quite low (1011 MW for the summer peak and 1077 MW for the winter peak in 2030), and previous planning studies, e.g. the 2018 long-range plan and TPL-001 studies, have shown that the transmission system should be able to serve the loads found in the low load forecast. Therefore, only a high load forecast was evaluated in addition to the medium load forecast.

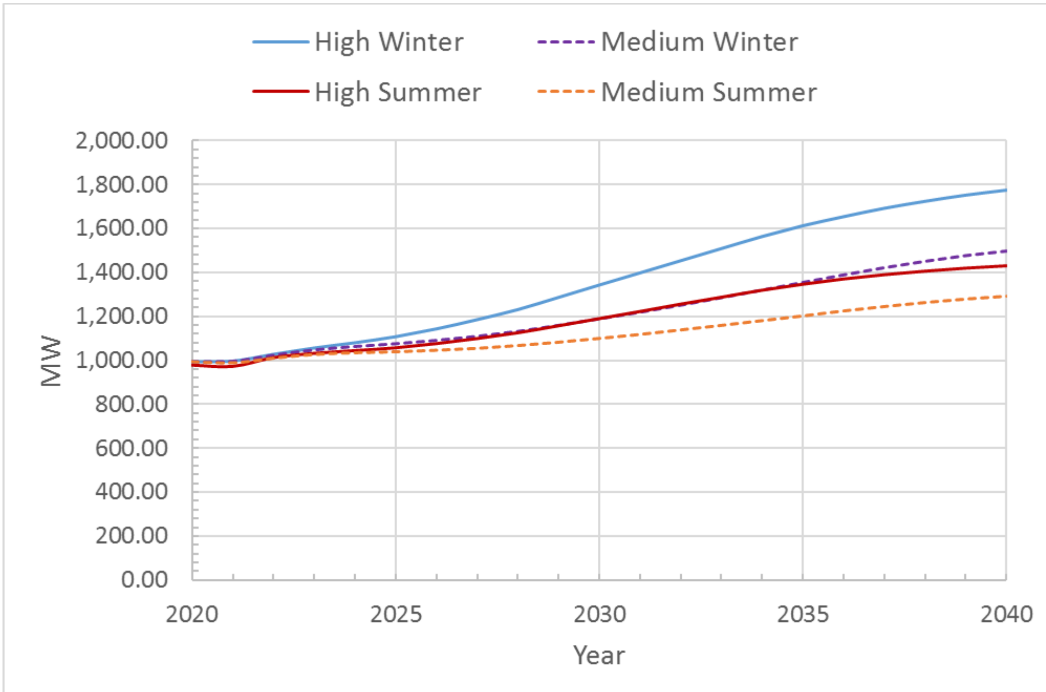
The high load scenario is meant to quantify the amount of load that the transmission system would need to serve if Vermont is on track to meet its total energy goal of 90 percent renewable energy by 2050, and EV adoption is significantly higher than current understanding of the EV market would suggest. The 2016 CEP sets energy reduction milestones to reduce energy consumption by 15 percent in 2025 and 33.33 percent in 2050. Goals for the remainder are to serve 25 percent from renewable sources by 2025, 40 percent by 2035 and 90 percent by 2050. The VSPC and particularly the DPS helped Itron determine how to increase electric vehicles and heat pump loads to be on track for the 2050 levels contemplated as part of the CEP. The medium load forecast scenario assumes that electric vehicles will reach a count of 256,400 by 2040 on the way to reach 60 percent of registered light-duty vehicles, or 279,000 vehicles, by 2050. The high load forecast scenario assumes that electric vehicles will reach a count of 412,700 by 2040 on the way to reach 90 percent of registered light-duty vehicles, or 418,000 vehicles, by 2050. The heat pump forecasts surpass the 2025 goal of 35,000 units. The low forecast is

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

[18] 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.

50,000 units and the high forecast is 65,000. The medium heat pump load forecast scenario assumes that heat pumps will reach 212,000 units by 2040. The high forecast scenario assumes 282,200 units by 2040, which is fairly close to the CEP goal of over 300,000 by 2050. The total peak loads of the medium and high forecasts are compared in the graph below.

LOAD FORECAST SCENARIO COMPARISON

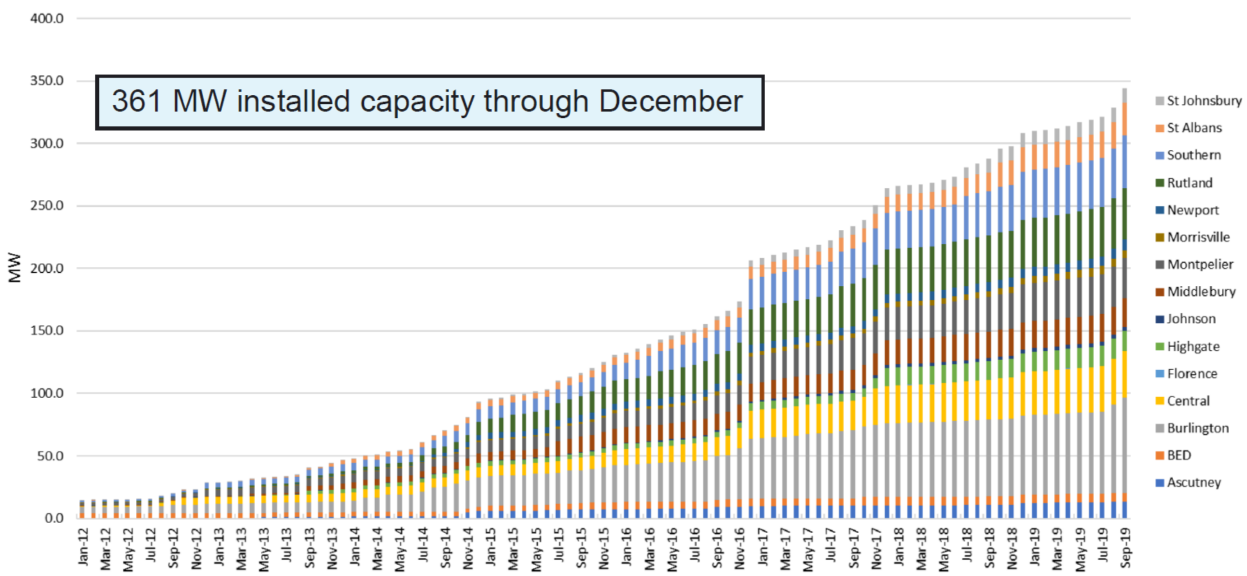


The graph shows that the summer high load forecast (red line) is almost the same as the summer medium load forecast (orange line) during the first five years of the planning horizon, and begins to exceed the medium load forecast after that point. The summer high load forecast is higher than the medium load forecast by 88 MW in 2030, 142 MW in 2035, and 137 MW in 2040. The winter high load forecast (blue line) is higher than the medium load forecast (purple line) by 153 MW in 2030, 257 MW in 2035, and 275 MW in 2040. The high load scenario advances the timing of the peak load levels within the ten-year horizon. For example, the 1101 MW summer peak load and the 1189 MW winter peak load occur three years earlier in the high load scenario as compared to the medium load forecast. Beyond the ten-year horizon, the high load scenario advances the peak load timing by five years or more. While significant load growth is anticipated, there remains uncertainty around the magnitude and the timing as discussed above 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 future long-range plans prepared every three years.

4.5.5.2 High solar PV forecast scenario

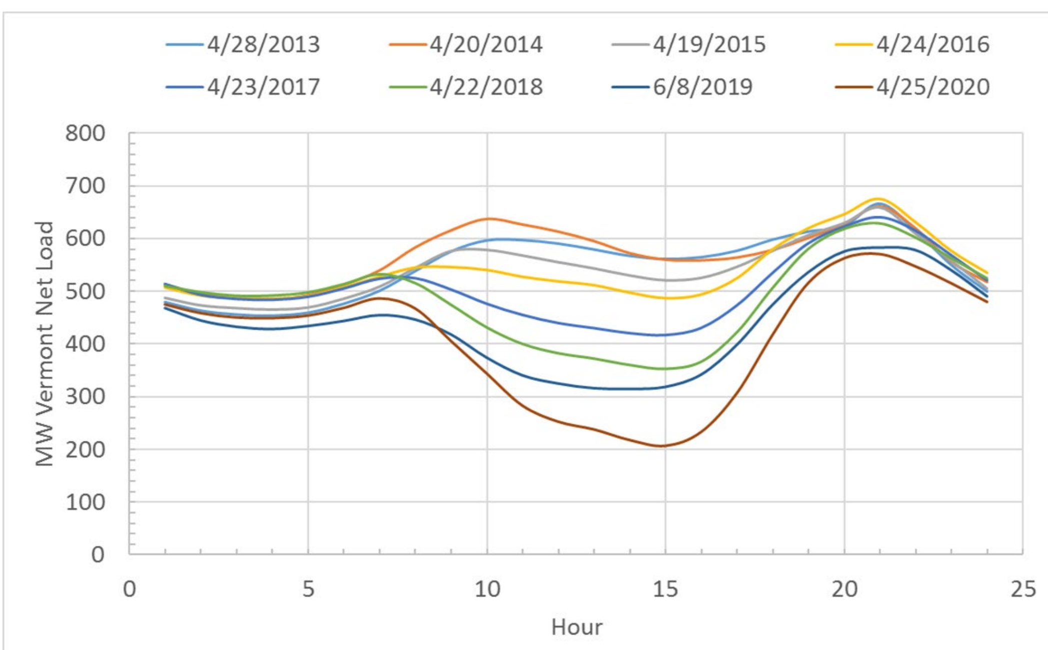
Solar PV has grown to nearly 361 MW as of December 2019. The following graph shows the geographical distribution of solar PV by VELCO planning zone. Since the completion of this analysis, the amount of solar PV has grown to 400 MW, and other DG has grown to 63 MW as of December 2020.

HISTORICAL SOLAR PV GROWTH



This rapid growth 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.

SOLAR PV IMPACT ON VERMONT NET LOADS

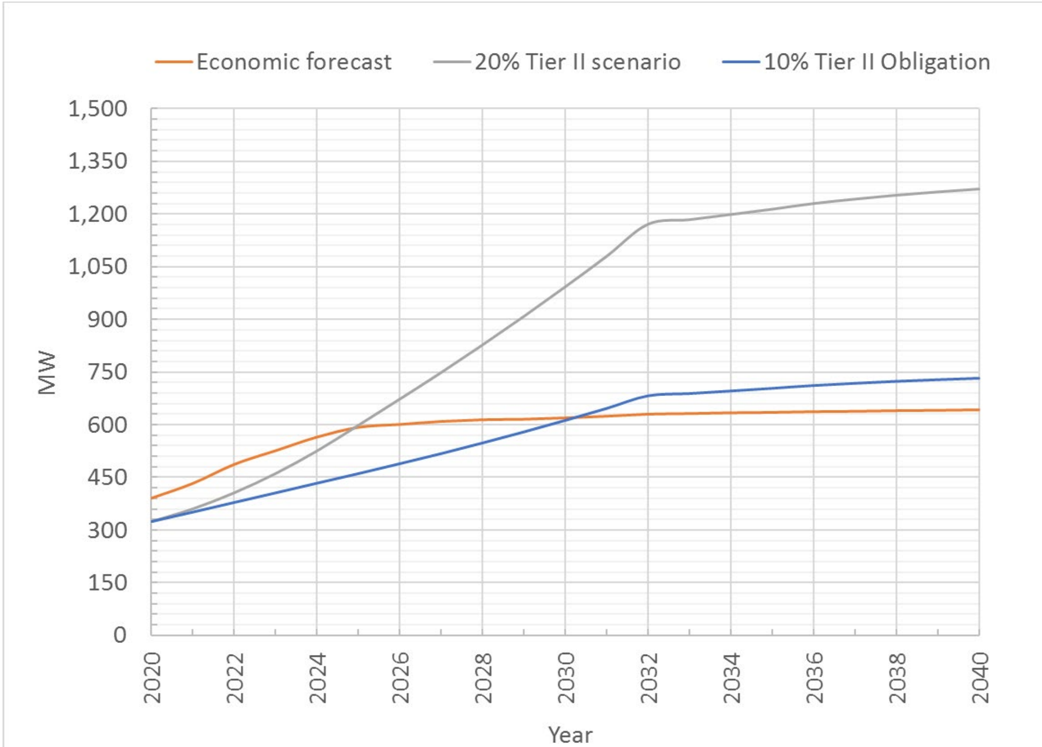


On a more local level, solar PV has started to reverse power flows through VELCO transformers serving distribution utilities. Flow reversal is not necessarily a reliability concern, but one could envision transformers and other substation equipment overloading eventually as solar PV continues to grow. 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 has clarified its planning procedures to ensure that appropriate studies are conducted when the aggregate level of new 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 threshold is reached for a single 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. Such studies require detailed models that adequately represent the dynamic behavior of generators in response to system disturbances.

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 cases of 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 increase 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 percent with the assistance of the distribution utilities. As noted previously, Itron provided a forecast that is incremental to the small-scale solar PV installed as of 2019. The Itron forecast utilizes 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 600 MW in 2025, and remains above the current 10 percent Tier II requirement (blue curve) until 2030. The 10 percent Tier II obligation was calculated to be 690 MW in 2032, and it continued to increase because the energy forecast increases. If the Tier II requirement is doubled to 20 percent, the Itron expected PV forecast is exceeded as early as 2025. The 20 percent Tier II scenario would reach 1190 MW in 2032. 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.

Solar PV Scenarios



5 Discussion of peak demand results

The following section presents the findings on the bulk transmission system, which includes Pool Transmission Facilities or PTF, 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

5.1.1 Medium load scenario

Results show that there are no bulk system reliability concerns that would require a system upgrade within the first ten years of the planning horizon. This result was achieved with our ability to adjust our tie line flows with New York and New Hampshire to position the system in such a way as to reduce flows on Vermont lines without overloading lines in the neighboring systems. In addition, we assumed that when subtransmission lines overload severely, they would trip or operators would manually disconnect these lines. In some cases, several subtransmission lines were overloaded and disconnected without negatively affecting the transmission system, but parts of the system would be isolated from the rest of the system and shed a large amount of load in some instances.

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 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 we recognize that budget concerns and priorities would preclude distribution utilities from mitigating all potential issues.

5.1.2 High load scenario

In the high load forecast scenario, peak loads are predicted to be significantly higher than the medium load forecast scenario, particularly in the second ten-year portion of the planning horizon. The high load forecast for the 2030 summer and winter peak loads are predicted to be 1188 MW and 1348 MW, respectively, compared to 1101 MW and 1189 MW in the medium load forecast. By adjusting our tie line flows, we were able to address transmission concerns. Our tie line flows can be adjusted by using phase shifting transformers that were installed as part of VELCO’s Northwest Reliability Project. This phase shifter solution was selected to optimize the use of the transmission system and postpone future upgrades as much as possible. In addition, although the winter peak load is much higher than the summer peak load, it was found that system concerns were not significantly more severe because transmission capacity is also greater during the winter. For example, transmission line ratings in the winter can be 25 percent greater than summer ratings due to cooler ambient temperatures.

The high load forecast predicted the 2040 summer and winter peak loads to be 1431 MW in the summer and 1774 MW in the winter. These loads are extremely high, and we are certain that the current system will not be able to accommodate these loads. Therefore, the 2040 load forecasts were tested assuming the use of load management. Based on discussions with the Vermont distribution utilities, it was understood that 75 percent of EV loads could be disconnected for several hours around the peak hour, or that this capability could exist in the near future. This reduction resulted in 2040 summer and winter peak loads of 1209 MW and 1471 MW, respectively. Results indicated that the transmission system could serve the reduced summer peak load with tie line flow adjustments, and no additional issues were identified with the reduced winter high load forecast loads.

Note that the results beyond ten years are quite uncertain. The study horizon is too long to capture transformative technological changes and other phenomena that are similarly difficult to predict. The analysis utilized simplifying methodology so that the analysis could be performed in a timely manner. For example, the loads in neighboring systems were modeled at the 2030 load level beyond the 2030 horizon because ISO-NE and other entities do not produce forecasts beyond the ten-year horizon, and we would use a straight line projection to adjust loads outside of Vermont. Since the Vermont system depends on its neighbors, and tie lines are adjusted assuming that neighboring systems can provide the needed support, we may find that higher loads outside of Vermont could cause Vermont transmission concerns earlier than anticipated. To the extent Vermont entities can manage loads either by disconnecting loads or with storage, future uncertainties such as these may be mitigated.

5.1.3 Sensitivity Analyses

VELCO reviewed the Integrated Resource Plans (IRP) and other reports prepared by the distribution utilities. Particular attention was paid to the load forecast and power supply sections, which indicated that the long-range plan scenario forecasts sufficiently covered the possible futures considered in these IRPs. All Vermont distribution utilities are committed to sustainability in one way or another. Some of these utilities have prepared resilience programs to address challenges produced by more frequent and severe extreme weather events. Jay Shafer of Northview Power, a Vermont weather expert, has performed a study of long-term weather trends. A brief summary of that analysis is provided before the glossary section. Some utilities go beyond the state's renewable energy requirements. BED has an ambitious goal, known as the Net Zero Energy goal, consisting of reducing and eventually eliminating fossil fuel use from the heating and ground transportation sectors. GMP owns approximately 100 MW of peaking generation capacity. Depending on various factors, including a potential major equipment failure, some or all of these peaking generators may be retired. Below is our review of the Net Zero Energy goal and the possible retirement of peaking generators.

5.1.3.1 *Burlington Net Zero Energy goal*

As noted on the BED website, Burlington's Net Zero Energy goal is to reduce and eventually eliminate fossil fuel usage in heating and ground transportation. This goal goes beyond Vermont's 90% renewable energy goal by 2050 in at least two ways. First, the city plans to source its entire energy supply for electric, thermal and ground transportation from renewables. Second, the city plans to achieve this goal twenty years earlier, i.e. by 2030. This goal is ambitious, but the city plans[19] to achieve this goal by im-

[19] https://burlingtonelectric.com/sites/default/files/inline-files/NetZeroEnergy-Roadmap.pdf

plementing a suite of policies and practices to effect change in four pathways, including: efficient electric buildings, electric vehicles, district energy, and alternative transport. This ambitious goal was compared with the business-as-usual scenario, and a slower implementation scenario achieving the Net Zero Energy goal by 2040, where electrification is not as rapid, heating and transportation electrification occurs when equipment fails, and renewable natural gas is not used.

Based on discussions with BED planners, our understanding is that the Net Zero Energy goal is expected to increase the BED peak load to 99 MW in 2030 and 111 MW in 2040 in the 2040 scenario. In the more ambitious 2030 scenario, the peak load is expected to grow to 141 MW in 2030, but then drop to 123 MW in 2040, as building efficiency improves overtime. As a point of comparison, the long-range plan forecasts a winter peak load of 93 in the extreme weather medium load scenario for the BED system. The long-range plan analysis did not identify any transmission system or BED system delivery substation deficiencies at that load level. One key difference between the long-range plan and the Net Zero Energy Scenario load projections is that the long-range plan forecast assumes that the winter peak will occur around 6 PM while the Net Zero Energy Scenario 2040 assumes that the winter peak will occur after 11PM assuming that 75% of electric vehicles will not charge their batteries before 11 PM. This may pose a challenge with respect to load management. BED customers may not readily accept to disconnect electric heat during peak-producing winter weather conditions, if such measures are contemplated. VELCO will continue to collaborate with BED planners to understand better the electric grid impacts and potential solutions under different scenarios.

5.1.3.2 Retirement of peaking generators

There has been consideration to retire conventional fossil fuel generation plants within Vermont. By and large, these units are of advanced age and called upon to run by ISO-NE system operators infrequently. When they are dispatched online, it is typically during a period of high demand for electricity. In such a scenario, it may be that the prices paid to generators are high, or that the power typically provided by large New England generators is inadequate to serve system load. However, these units may also be called upon by Vermont system operators in order to address local issues. Sometimes, necessary transmission line maintenance could expose nearby system elements to adverse impacts if a contingency were to occur, such as could occur in an N-1-1 scenario. To reduce negative impacts, the operator may turn a unit online.

As noted earlier, the long-range plan analysis assumes that approximately 100 MW of peaking generation would be available to support peak loads. If some or all of these generators retire during the planning horizon, the impact will be similar to increasing Vermont load by the same amount, and the timing of any system deficiencies would be advanced by a few years. To examine the potential impacts to the transmission system if these conventional generators were retired, analysis was undertaken with these units offline. McNeil, the largest generator in Vermont, was left offline in accordance with planning practice as described above, and the Ryegate plant and renewable generators were left online.

The results of this analysis show several new and accelerated subtransmission concerns for the loss of a single element. Some thermal overloads that were not expected to occur until after the 10 year planning horizon were now seen to occur just within ten years, that is, in the late 2020s. It was also found that the retirements exacerbated some subtransmission voltage violations previously observed in the base analysis. Under N-1-1 conditions, there are a variety of observed thermal and voltage violations. Some of these were not expected to occur with the generators in service, and some that were expected to occur were accelerated by a few years. For the most part, these are seen in the late 2020s again, but some are accelerated closer to the present.

It should be noted that any plant in particular may or may not be able to contribute to the mitigation of any of these issues; prior to the retirement of any of these generating units, specific analysis should be undertaken to ensure that the transmission and subtransmission systems perform reliably.

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 percent 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.

The St Albans transformer was found to be overloaded in our analysis. Upon further review, it was determined that the transformer rating was limited by the VELCO 34.5 kV bus rating. We have started using the rigid bus rating methodology outlined in the IEEE 605 standard, and this has increased the bus rating above the transformer rating, and eliminated the need to upgrade the transformer.

The long-range plan analysis also identified a Middlebury transformer overload, which can be resolved by a routine change of a monitoring and control instrument. Similar to the bulk system issues, several other predominantly bulk issues were observed for N-1-1 outage events. These concerns can, in some cases, be addressed by opening transformers and subtransmission lines. In other cases, opening transformers and lines may result in load shedding, albeit less than the proposed 300 MW ISO-NE threshold. Planning risk assessments would consider mitigating the worst subtransmission line overloads and those that occur for a large number of outages, but we recognize that budget concerns and priorities would preclude distribution utilities from mitigating all potential issues.

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.

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. The following table identifies sub-transmission areas with potential reliability issues. 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.

Sub-transmission Potential Reliability Issues Grouped by Location							
Location	**Year Needed**[20]	**90/10 Load Forecast for Year (MW)**[21]	**Contingency**	**Reliability Concern**	**N-1 Criteria Violation**	**Affected DUs**	**Lead DU**
Ascutney	2020	< 987	Subtransmission	Thermal Low Voltage	Maple Ave – River Rd – Charlestown	GMP / PSNH	GMP
Ascutney	2020	< 945	Subtransmission	Thermal	Lafayette – Bridge St. – Bellows Falls	GMP / PSNH	GMP
Ascutney	2020	974	Subtransmission open end	Thermal	Windsor – Windsor V4	GMP	GMP
Ascutney	2021	992	Transformer Subtransmission	Low Voltage	Lafayette – Bridge St. – Bellows Falls	GMP / PSNH	GMP
Ascutney	2021	992	Transformer Subtransmission	Thermal	Highbridge – Ascutney	GMP / PSNH	GMP
Blissville	2020	< 945	Transformer	Thermal	West Rutland – Castleton	GMP	GMP
Blissville	2021	992	Transformer	Low Voltage	Blissville area	GMP	GMP
Burlington	2020	< 948	Subtransmission open end	Voltage	Richmond area	GMP / VEC	GMP
Montpelier	2020	< 970 Winter	Subtransmission open end	Low Voltage	Moretown – Irasville – Madbush (winter)	GMP / WEC	GMP
Montpelier	2020	< 945	Transformer Subtransmission	Thermal	Berlin – Montpelier	GMP	GMP
Montpelier	2021	1000	Subtransmission	Thermal	Barre – South End	GMP	GMP
Montpelier	2027	1116	Subtransmission	Thermal Voltage	South Barre – Websterville	GMP	GMP
Rutland	2020	< 970 Winter	Subtransmission open end	Low voltage	Snowshed (winter)	GMP	GMP
Rutland	2020	< 948 Winter	Subtransmission open end	Low voltage	Brandon – Mendon	GMP	GMP
Southern	2023	1050 winter	Subtransmission & open end	Thermal	Manchester – East Arlington	GMP	GMP
Southern	2028	1157 winter	Subtransmission open end	Thermal	Newfane – Jamaica	GMP	GMP
St. Albans	2025	992	Transformer Transmission	Low voltage	Sheldon	GMP / VEC	GMP
St. Albans	2020	981	Transmission Transformer	Thermal	Georgia – Ballard Road	GMP / VEC	GMP

The subsystem near the Stowe substation is served from the south by a transmission line and a sub-transmission 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 2020. Since the Lamoille County project was permitted with the preferred double circuit design, this low voltage is not considered a concern that needs mitigation.

[20] Projects needed in past studies listed as 2020 in this table

[21] Load levels tested in prior plans differ from the load levels in 2021 and beyond

6 Discussion of DG (solar PV) results

6.1 Summary of the 2018 generation hosting analysis

In the 2018 plan, VELCO assessed the system's capacity to accommodate a large amount of distributed generation or DG, which has been almost exclusively solar PV. The system was tested at a typical daytime load level with all other renewable resources (hydro, wind, wood, and methane) and the Highgate converter modeled at full capacity, assuming that existing renewable generation would not be curtailed to accommodate new solar PV generation. All gas and diesel units were modeled out of service. In addition, the Plattsburg-Sand Bar 115 kV tie line was modeled at 0 MW and the Comerford-Granite tie line was modeled at 100 MW. The analysis was performed with the total amount of solar PV modeled at 500 MW and at 1000 MW with the assumption that solar PV would continue to be developed in the same way that it has historically.

At the 500 MW level, voltage collapse was observed in the northern portion of the system. Assuming this voltage concern is resolved, overloads would be observed along the Highgate-Georgia transmission path. In addition, system losses were seen to increase due to higher flows caused by generation being in excess of the tested electric demand. The system was tested at the 1000 MW DG level to identify system limitations and potential solutions. In addition to testing the system based on historical geographical distribution, the system was tested assuming that future solar PV would grow in proportion to local electrical demand or energy consumption. It was found that the system performed similarly irrespective of these three geographic distributions. System losses were more than twice the level observed at the 500 MW DG level. Many transmission lines overloaded. Low and high voltages were observed. A transmission-only solution and a storage-only solution was considered to address these concerns.

The 2018 long-range plan also discussed an optimized geographic distribution of DG based on transmission system capacity. This hosting capacity analysis was structured in a manner that would produce the maximum amount of DG. The assumptions were optimistic and some were even somewhat unrealistic. For example, the Plattsburgh to Sand Bar and Comerford to Granite tie lines were maintained at 0 MW, which is not the typical flow on these tie lines. It was assumed that the distribution system constraints would be resolved, which may not be the case. It was also assumed that larger FERC jurisdictional generation projects in the ISO-NE generation interconnection queue would not go forward. These assumptions were modified in the current long-range plan.

6.2 2021 Hosting capacity sensitivity analysis

The system was tested at a load level of 560 MW, without system losses. 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 DG of 404 MW with and without the proposed FERC jurisdictional projects of 90 MW of solar. The system was also modeled including those projects that are currently "proposed" – 120 MW of small-scale solar PV – in Vermont distribution utility queues in addition to the currently installed DG with and without the proposed FERC jurisdictional projects. Transmission overloads were observed across the Sheffield-Highgate Export Interface (SHEI[22]) and along the western edge of the state near Essex, Middlebury, and New Haven. There were also subtransmission overloads near Bethel, Windsor, and Pittsford. These results indicate that with DG levels just above the currently installed amount, the system may not have sufficient capacity to accommodate all renewable generators operating at full output. This does not mean that upgrades are necessarily needed. Dispatchable generators can be reduced and future storage or load management can be utilized 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 DER levels up to 1250 MW to examine the impact that may be seen by doubling the Renewable Energy Standard Tier II objectives from 10 percent to 20 percent. Contrary to the 2018 plan, distribution transformer ratings were taken into account, the Plattsburg-Sand Bar tie line was modeled at 50 MW instead of 0 MW, and FERC jurisdictional generation projects were modeled in and out of service. With additional flow on the system, several transmission facilities were found to be affected. The overloads include lines from Highgate to Cavendish and to the Vermont/New Hampshire border. The Irasburg, Middlebury, Windsor, Vergennes, and Vernon Road transformers also overloaded. We also observed excessively high voltages across the state, primarily on subtransmission facilities, and a voltage sag at the New Haven 345 kV substation. Further, the subtransmission system would experience severe overloads. Below is an illustration of the transmission and substation facilities that would be affected at a 1000 MW DG level with additional flows across tie lines.

[22] Additional information can be found at https://www.vermontspc.com/grid-planning/shei-info

LOCATION OF TRANSMISSION CONSTRAINTS AS A RESULT OF HIGH SOLAR PV

Increasing DG in Vermont will potentially affect the transmission system outside of Vermont. Transmission overloads were observed in New Hampshire at DG levels just above today's levels, and they will be aggravated as Vermont continues to increase DG. Depending on the nature and extent of these system concerns, ISO-NE may create a large export interface encompassing parts of Vermont and New Hampshire, and manage these concerns with generation curtailments in Vermont and New Hampshire.

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 listing of transmission and subtransmission system concerns found at the 1000 MW DG level, 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.

Thermal Impacts of High Solar PV Scenario

Upgrade	DER level at the 1st violation	Number of violation events	Category	Length (Miles)	Estimated Cost	Affected DUs	Lead DU
Rebuild 115 kV line between Highgate and Georgia	450 MW	4	Bulk	17	$61M	All Vermont DUs	GMP
Rebuild 115 kV line between Sand Bar and Essex	450 MW	1	Bulk	11.2	$34M	All Vermont DUs	GMP
Rebuild Gorge - McNeil-35 kV line	450 MW	1	Subsystem	2.3	$0.9M	GMP	GMP
Rebuild Brandon - Mendon Tap 46 kV line	450 MW	(No outage) 487	Subsystem	14.6	$5.8M	GMP	GMP
Rebuild Windsor-Highbridge 46 kV line	450 MW	(No outage) 485	Subsystem	6.2	$2.5M	GMP	GMP
Rebuild Newfane-G Pacific 46 kV line	450 MW	1	Subsystem	11.9	$4.8M	GMP	GMP
Rebuild Websterville-South End 35 kV line	450 MW	(No outage) 487	Subsystem	2.9	$1.2M	GMP	GMP
Rebuild 115 kV line between Williston and New Haven substations	500 MW	(No outage) 45	Bulk	20.8	$56M	All Vermont DUs	GMP
Rebuild 115 kV line between Middlebury and West Rutland	600 MW	1	Bulk	28	$104M	All Vermont DUs	GMP
Rebuild Taftsville – Windsor 46 kV line	600 MW	470	Subsystem	10.6	$4.2M	GMP	GMP
Rebuild 115 kV line between Essex and Williston substations	650 MW	(No outage) 478	Bulk	8.3	$27M	All Vermont DUs	GMP
Replace Vernon Road transformer	650 MW	1	Predominantly Bulk	N/A	$3.8M	All Vermont DUs	GMP
Rebuild E Barnard-Woodstock 46 kV line	650 MW	484	Subsystem	10.2	$4.1M	GMP	GMP
Rebuild 115 kV line between New Haven and Vergennes	700 MW	3	Bulk	6.7	$35M	All Vermont DUs	GMP
Rebuild Smead Road - Brandon 46 kV line	700 MW	1	Subsystem	8.4	$3.4M	GMP	GMP
Replace Irasburg transformer	800 MW	2	Predominantly Bulk	N/A	$3.9M	All Vermont DUs	GMP
Rebuild Windsor V4 - Windsor 46 kV line	800 MW	2	Subsystem	1.5	$0.6M	GMP	GMP
Rebuild 115 kV line between Georgia and Global Foundries	850 MW	1	Bulk	17.7	$45M	All Vermont DUs	GMP
Rebuild 115 kV line between New Haven and Middlebury	900 MW	1	Bulk	7.5	$21M	All Vermont DUs	GMP
Rebuild 115 kV line between North Rut-land and Coolidge	900 MW	1	Bulk	23.8	$70M	All Vermont DUs	GMP
Replace Middlebury equipment	900 MW	19	Predominantly Bulk	N/A	$0.1M	All Vermont DUs	GMP
Rebuild Little River – Duxbury 35 kV line	900 MW	2	Subsystem	3.3	$1.3M	GMP	GMP
Replace Windsor transformer	950 MW	6	Predominantly Bulk	N/A	$4.9M	All Vermont DUs	GMP
Replace Vergennes transformer	950 MW	1	Predominantly Bulk	N/A	$4.5M	All Vermont DUs	GMP
Rebuild 115 kV lines between West Rut-land & North Rutland	1000 MW	1	Bulk	5.1	$14M	All Vermont DUs	GMP
Rebuild Ballard Rd –Clark Falls 35 kV line	1000 MW	4	Subsystem	4.3	$1.7M	GMP	GMP

These upgrades could be avoided in part with storage, load management, and generation curtailment. Regardless of the solution, it is not without cost, and this cost will be borne entirely by 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 event. It is likely that the chosen solution will be a combination of transmission upgrades and non-transmission upgrades, which will require careful orchestration of non-transmission upgrades 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 table in the previous page lists concerns being addressed, the DG level at which the first system concern arises, the number of system outages that would cause the concern, and those concerns that would occur with no outages. These attributes can help determine whether an operational or generation curtailment solution is a viable solution. For example, if a system concern occurs at a DG level of 600 MW as a result of a transformer outage, 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, 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.

The Vergennes constraint is an existing local constraint where new generation is highly restricted to prevent the overload of a distribution transformer at the Vergennes substation. The available historical data illustrated a number of concepts:

- The types of installed and proposed generation affect the duration and frequency of the exposure to system concerns;
- The types of customer loads affect the duration and frequency of the exposure to system concerns;
- The geographical and temporal diversity of loads and generators affect the location and type of solution;
- The size of flexible and controllable loads and generators affect the design of the solution; and,
- The complexity, reliability and security of the solution should also be taken into consideration.

Although not discussed at the VSPC generation constraint review, cost allocation is a critical consideration. Generation constraints are not reliability concerns requiring mitigation at the cost of electricity consumers unless it is determined that the societal benefits justify putting the burden on consumers.

6.2.1 Optimized solar PV Distribution

The table above shows that system concerns can occur as early as 450 MW of DG depending on the specific operating condition and DG location. This happens as the system study allowed DG to grow relative to existing distributions regardless of system capacity. While these resources grew, no other adjustments were made to existing traditional market participant generation resources to make room for the additional DG. The 2018 long-range plan 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 five percent over applicable equipment ratings under optimistic system conditions (such as no imports from New York along the Plattsburgh to Sand Bar PV20 line), and assuming no future FERC jurisdictional generation projects would connect to the system. This 2018 analysis yielded a hosting capacity of 1058 MW.

The optimized distribution analysis was updated in this plan to illustrate how the hosting capacity of the system would be affected by changing these 2018 assumptions of operating conditions to examine how different circumstances may impact the system. Imports along the PV20 line were increased to 50 MW, which is about one third of its maximum operational limit, and 90 MW of FERC jurisdictional generation projects were modeled in service in Vermont as well as 50 MW just outside the Southern zone of Vermont, connected near the Vernon Road substation. DG was allocated such that distribution transformer ratings would not be exceeded, and it was found that, although this could limit DER at individual distribution substations, it had a marginal effect on zonal hosting capacity.

Effects of imports and FERC jurisdictional projects on Optimized DG distribution

Zone Names	Optimized Distribution Spring 2030 (PV20 at 50 MW, FERC projects off)		Optimized Distribution Spring 2030 (PV20 at 50 MW, FERC projects on)	
	Net loads	DG Capacity	Net loads	DG Capacity
St. Johnsbury	-13.4	30	-13.4	30
Newport	10.5	5.4	10.5	5.4
Highgate	3.4	19.8	3.4	19.8
Johnson	-17.7	20	-17.7	20
Burlington	-46.4	126.2	-0.2	80
BED	30.4	7.5	30.4	7.5
Montpelier	-23.4	76.8	-22.9	76.3
Morrisville	-6.9	25	-6.9	25
Middlebury	-33	50	-42.7	59.7
Rutland	-102.6	151.9	-99.4	148.7
Ascutney	-34.6	73	-29.9	68.3
Southern	-190.9	251.5	-133.7	194.3
St. Albans	6.8	40	6.8	40
Central	-59.3	98.7	-33.6	73
Florence	2.4	20	2	20.4
Zonal Totals	-429.7	995.8	-302.3	868.4
Gross load/Loss	561 / 59		561 / 59	

The results of this analysis show that PV20 imports had nearly a one-for-one impact on DG hosting capacity, reducing the hosting capacity amount from 1058 MW in the 2018 study to 996 MW in this year's study. FERC jurisdictional generators, modeled in the Burlington, Central and Southern zones, had a direct impact in these zones and, minimally, in adjacent zones. The combined impact is more than a one-for-one impact, resulting in a decrease in hosting capacity to 868 MW. Even so, the 868 MW hosting capacity is an optimistic one, and it does not signify that this is a no-cost alternative. One critical assumption that was made is that DG projects would be designed in a manner consistent with the applicable design standards. For example, it was assumed that DG projects would provide grid support. A five percent overload was allowed to recognize that perfect conditions resulting in all renewable generators operating at their full capacity rarely occur, if ever, and some amount of storage or load management will be installed to address excessive generation when it does happen. A future with significant amounts of DG requires local and centralized controls to manage variable loads and generation, and maximize the benefits of renewable generation. However, technology that enables DG monitoring, management and control, and wholesale market participation, may prove to be capital-intensive.

The table below shows the modeling assumptions of load and DG arrived at by achieving the optimized state solar distribution. The currently installed capacity was also updated this year with input from the various distribution utilities and was the starting point for modeling all of the solar scenarios. This chart shows how the assumption of the PV20 flow impacts achievable solar penetration in the Northern regions of the state compared to the 2018 study as more flows are contributed to the Northwestern transmission in the state.

Optimized solar PV distribution by load zone

Zone names	Gross loads[1] (MW)	Installed Solar PV as of 2020 (MW)	Optimized solar PV distribution 2018 study (MW)	Optimized solar PV distribution 2021 study (MW)
Newport	15.9	5.4[2]	10.3	5.4[2]
Highgate	23.2	17.7	15.5	19.8
St Albans	46.8	29.7	42.9	40
Johnson	2.3	3.9	16.4	20
Morrisville	18.1	10.8	50.7	25
Montpelier	53.4	28.2	104.9	76.8
Lyndonville/St. Johnsbury	16.6	10.5	12.1	10/20
BED	37.9	7.5	5.6	7.5
Burlington/GF	79.8/45	75.8	107.4/20	126.2
Middlebury	17	27.9	57.7	50
Central	39.4	39	91.2	98.7
Florence	22.4	0.2	21.2	20
Rutland	49.3	41.3	164.6	151.9
Ascutney	38.4	18.4	112.8	73
Southern	60.6	44.5	224.9	251.5
Total	566	360.8[2]	1058.3	995.8[3]

1 Listed as gross load without losses

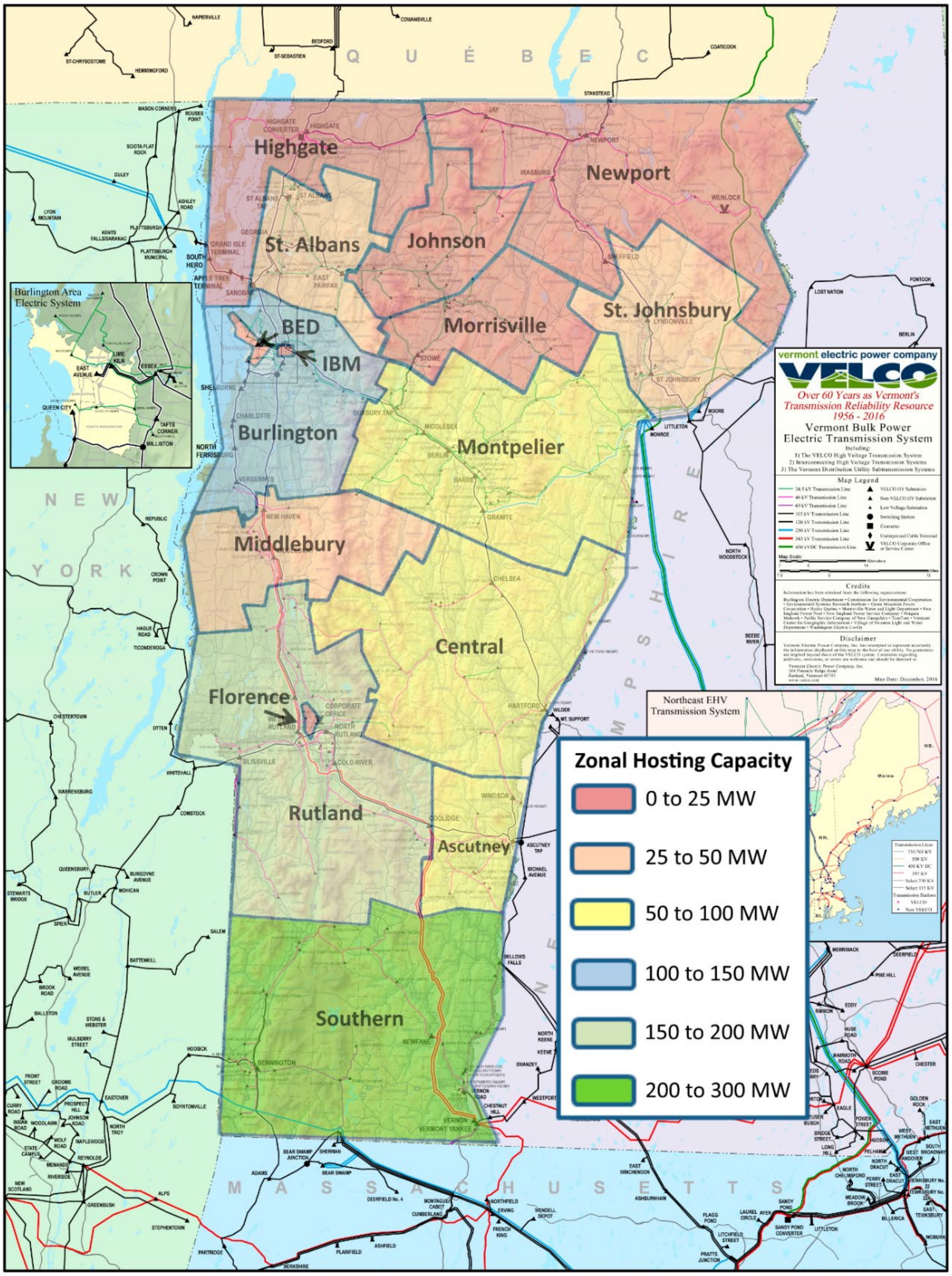
2 7.3 MW of additional solar installations fall in the Newport zone and NVDA RPC that are served by HQ under normal circumstances. Some of these installations may reside in Vermont and be fed by Vermont Distribution Utilities, but were not added to these totals as they are not normally fed from Vermont transmission.

3 The Optimized Distributions shown in this table also include other existing mixed DG resources within the zonal totals.

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 related upgrades. The map shows how resources are more easily accommodated in the southern regions and more difficult to accommodate in the northern regions, which are further from major transmission and closer to other large generation and energy sources. Distribution utilities have created maps to facilitate generation project siting with respect to available distribution capacity.[23]

[23] 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.

SOLAR PV DISTRIBUTION OPTIMIZED BASED ON EXISTING TRANSMISSION CAPACITY



The following two tables show the same solar allocations from the above optimized distribution case with FERC jurisdictional future projects left out of service. The total installed solar 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 regional and entity specific initiatives.

Optimized solar PV distribution by Utility

Zone names	Installed solar PV as of 2020 (MW)	Additional solar PV (MW)	Optimized solar PV distribution (MW)
BED	7.5	0	7.5
GMP	311.4	554	865.4
VEC	28.2	13.5	41.7
VPPSA	10.8	34.4	45.2
SED	2.5	1.3	3.8
WEC	3.6	5.0	8.6
Totals	360.8	608.2	969

Optimized solar PV distribution by Regional planning Commission

Zone names	Installed solar PV as of 2020 (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)	49.7	**30.1**	79.8	143.6	109.8	71.8	
Bennington (BCRC)	17.5	**66.4**	83.9	121.9	85.9	48.9	1
Central Vermont (CVRPC)	29.1	**44**	73.1	342.5	151.4	103.6	2
Chittenden (CCRPC)	74.1	**41.5**	115.6	393.6	275.7	157.9	3
Lamoille (LCPC)	9.1	**25.5**	34.6	135.0	91.9	48.7	4
Northeastern (NVDA)	20.6[7]	**28**	48.6	27.4	22.6	17.9	5
Northwest (NRPC)	34.2	**8.6**	42.8	247.0	166.2	87.9	
Rutland (RRPC)	41	**126.6**	167.6	304.4	113.4	50.4	
Southern Windsor (SWCRPC)	18.8	**56.7**	75.5	154.7	80.7	43.6	2
Two River OTQ (TRORC)	38.7	**59.3**	98	190.5	125.5	66.5	6
Windham (WRC)	28.1	**148.2**	176.3	60.7	45.7	30.7	4
Totals	360.8[7]	**636**	996.8[8]	2121.2	1268.8	728.0	

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

7 7.3 MW of additional solar installations fall in the Newport zone and NVDA RPC that are served by HQ under normal circumstances. Some of these installations may reside in Vermont and be fed by Vermont Distribution Utilities, but were not added to these totals as they are not normally fed from Vermont transmission.

8 The total Solar PV Distribution also includes 44 MW of currently installed mixed resources of DG within the Optimized Distribution column.

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.

LIMITING ELEMENTS OF DG OPTIMIZED DISTRIBUTION BY ZONE

Element Name	Voltage Level	Planning Zones Limited
Highgate to St. Albans	115 kV	SHEI, Lyndonville
Sandbar to Essex	115 kV	SHEI, St. Albans
Taft Corners to Williston	115 kV	Montpelier, Morrisville, Johnson
Williston to New Haven	115 kV	Burlington
North Rutland Transformer	115/46 kV	Rutland
Bennington Transformers	115/46 kV	Bennington
Pittsford Village to East Pittsford	46 kV	Middlebury, Rutland
West Rutland to Hydeville	46 kV	Rutland, Florence
East Barnard to Woodstock Tap	46 kV	Central
Taftsville to Windsor	46 kV	Central, Ascutney
Windsor to Highbridge	46 kV	Ascutney
South Barre to Websterville	34.5 kV	Montpelier

6.2.2 STORAGE AS A MITIGATING STRATEGY

In the 2018 long range plan, it was found that storage could be utilized to mitigate thermal and voltage concerns with the business-as-usual DG distribution. Storage was modeled where thermal and voltage concerns were located, and that analysis yielded approximately 400 MW of storage requirements. In addition, the optimized DG distribution was compared to the business-as-usual distribution, and it was found that approximately 250 MW of storage with 5 hours of energy would be needed to manage the excess energy. The assumption in these scenarios is that the storage devices would be properly located.

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. Studies should be conducted to evaluate system impacts of storage projects, as is done for DG and large loads. 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.

6.3 Potential congestion[24] impacts

VELCO hired Daymark Energy Advisors to evaluate congestion and system performance risks under a scenario modeling 1000 MW of DER penetration and high transportation and heating sector electrification, which increases load by 310 MW in the year 2030. Using a risk-based planning software[25], Daymark examined three different characteristic days for the modeling effort:

1. an extremely cold winter peak day (as one might expect a few days into a multi-day cold snap) with snow fall eliminated solar production and still air limiting wind production,
2. a cool clear spring day with light load and high renewable generation (solar and wind), and high hydro-electric generation, and
3. a mild clear fall day with light loads and high solar generation and wind production.

Under the conditions studied, net load served by the transmission system could range widely, even becoming negative (i.e., power is being pushed onto the transmission system from the sub-transmission and distribution systems). Net load served by the transmission system (after accounting for additional electrification load and BTM generation) ranges from -160 MW under extreme spring test conditions to 1,200 MW under extreme winter peak conditions.

The analysis reports congestion cost impacts at the 115 kV level in Vermont. Daymark found that the system was exposed to extreme localized congestion, particularly in the cases where the system experienced negative net load in spring and fall. Observed system voltages were also unacceptable in many simulations.

In this study, the congestion prices are best interpreted as a measure of how effectively the operators would be able to manage the system, rather than as direct measure of price risk. The extreme congestion prices under many of the studied conditions suggest that operators may have to take extraordinary measures (including the curtailment of BTM renewable generation on the DUs systems), or in the most extreme cases, may have no means (given the currently available controls and configuration of the system) to secure the system.

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[24] Congestion is a phenomenon that occurs in electricity markets when scheduled load and generation transactions would cause power flows to exceed system capacity. Positive congestion increases prices, and is usually an indication that load exceeds generation. Negative congestion decreases prices, and is usually an indication that generation exceeds load.

[25] The risk-based power system planning tool allows the planner to assess the performance of the power system under different test scenarios by explicitly considering the impact of the loss of system element(s) and the risk around key operational inputs such as load, fuel prices, intermittent resource production, and weather profiles using a probabilistic analysis. The risk-based planning tool provided stakeholders insights into the trade-offs amongst alternative power system expansion plans in an environment where investment decisions are made under uncertainty. A risk-based planning analysis allows planners to assess tradeoffs between risk mitigation and cost minimization in their decision process that traditional transmission expansion planning approach using risk-neutral static models would not have explicitly considered.

6.4 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 not only the amount of additional renewable generation, but also its location. This solar PV analysis shows that the integration of over 1000 MW of solar PV 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, as well as reinforcements to Vermont's transmission, subtransmission, and distribution systems.

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 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, while continuing to provide 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

Jay Shafer, PhD, President and CEO of Northview Weather LLC, has been performing an analysis of long-term weather trends on the electric grid. Doctor Shafer generously offered a summary of his analysis, which is provided below.

Extreme weather events can cause disruptions to the transmission system primarily through infrastructure failures. These failures may occur when a weather-induced stress or load (e.g., ice and/or wind) exceeds rated design standards. On the distribution system these disruptions also occur from infrastructure failures, but more frequently are a result from trees conflicting with overhead lines and poles within or near right-of-ways.

Seasonal climatic trends across Vermont indicate warming temperatures and increases to precipitation. This warming is most pronounced in the late summer and early fall, as the late summer season expands wider into early fall. Precipitation increases are most pronounced during the winter season with equal increases across the other three seasons. These climatic trends are also causing weather systems to be wetter and warmer. One strong signal that comes out of this trend is the widening of the fall wind storm and early winter wet snow season - this widening increases overall weather risk exposure. Over 50% of all distribution power outage disruptions occurred from October to December from 2010-2019. The most extreme storms (e.g., Superstorm Sandy, Tropical Storm Phillippe extratropical transition) still appear most likely during 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.

Given the low frequency of hurricanes/tropical storms, and ice storms, there were no trends to the frequency of these storm systems in the last 40 years. However, the current and future climate will continue to support the potential intensity of these storms. Tropical storm systems as hurricanes will likely have a greater potential to be stronger given increases in ocean temperatures associated with climate change. Wetter winter storms may increase the severity of any ice or wet snow storms. 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.

Changes to the overall weather risk exposure to the transmission system result primarily from storms becoming potentially more intense and not more frequent.

8 Public input on the 2021 plan update

9 Glossary & Abbreviations

9.1 Glossary

90/10 load—An annual forecast of the state's peak electric demand (load) where there is a 10-percent chance that the actual system peak load will exceed the forecasted value in any given year or, stated another way, it is expected that on the average the forecast will be exceeded once every ten years.

affected utility—Affected utilities are those whose systems cause, contribute to or would experience an impact from a reliability issue.

base load—A base load power plant is an electric generation plant that is expected to operate in most hours of the year.

blackout—A total loss of power over an area; usually caused by the failure of electrical equipment on the power system.

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

bus— In power engineering, a "bus" is any graph node of the single-line diagram at which voltage, current, power flow, or other quantities are to be evaluated. This may or may not correspond to the physical busbars in substation. (Source: Wikipedia.)

capacitor—A device that stores an electrical charge and is typically used to address low voltage issues on a power system.

conductor—Part of a transmission or distribution line that actually carries the electricity; in other words, the wire itself. The wire or conductor is just one part of a transmission line; other parts include the poles and the insulators from which the conductor is hung. A conductor must have enough capacity to carry the highest demand that it will experience, or it could overheat and fail.

contingency—An unplanned event creating an outage of a critical system component such as a transmission line, transformer, or generator.

demand—The amount of electricity being used at any given moment by a single customer, or by a group of customers. The total demand on a given system is the sum of all of the individual demands on that system occurring at the same moment. The peak demand is the highest demand occurring within a given span of time, usually a season or a year. The peak demand that a transmission or distribution system must carry sets the minimum requirement for its capacity.

demand-side management (DSM)—A set of measures utilized to reduce energy consumption. Energy conservation is one kind of DSM.

dispatch—As a verb: turning on or off, or setting the value or output of a generator, a capacitor bank, reactor or transformer setting.

distributed generation (DG)—Power generation at or near the point of consumption in contrast to centralized generation that relies on transmission and distribution over longer distances to reach the load. Generally DG is smaller in scale and centralized, base load power.

distribution—Distribution lines and distribution substations operate at lower voltage than the transmission systems that feed them. They carry electricity from the transmission system to local customers. When compared to transmission, distribution lines generally use shorter poles, have shorter wire spans between poles and are usually found alongside streets and roads, or buried beneath them. A typical distribution voltage would be 13.8-kV.

distribution utility—A utility in the state of Vermont that is responsible for owning, operating, and maintain the distribution part of the electric system within an area.

docket—A court case. As used in this plan, the term refers to a case before the Vermont Public Service Board.

Docket 7081—The Public Service Board case that established Vermont's current process for transmission planning. The formal title of the case is "Investigation into least-cost integrated resource planning for Vermont Electric Power Company, Inc.'s transmission system."

elective transmission—Projects needed to connect generation to markets and to increase the capacity of a transmission corridor that otherwise limits the ability to sell power from one part of the system to another. Such projects, needed for purposes other than reliability, are categorized as elective transmission, and are financed by the project developer, not the end-us customer.

easement—A right to use another's land for a specific purpose, such as to cross the land with transmission lines.

economic transmission—Transmission projects needed to achieve economic benefits, such as reducing system losses, improving market efficiency, or reducing the cost of serving customer demand.

forward capacity market—A marketplace operated by ISO-NE using an auction system with a goal of purchasing sufficient power capacity for reliable system operation for a future year at competitive prices where all resources, both new and existing, can participate.

generation or generator—A device that converts other forms of energy into electrical energy. For example, solar energy from a photovoltaic panel or mechanical energy from an engine, a water wheel, a windmill, or other source, can be converted into electrical energy.

kilowatt-hour (kWh)—One thousand watt-hours. A watt-hour is a measure of the amount of electric energy generated or consumed in a given period of time.

kilovolt (kV)—One thousand volts. Volts and kilovolts are measures of voltage.

lead distribution utility -A utility selected by the affected utilities to facilitate decision-making and to lead the effort to conduct the NTA analysis

load—see ***demand***.

megawatt (MW)—One million watts. Watts and megawatts are measures of power. To put this in perspective, the peak power demand for the New England region is approaching 30,000 MW or 30,000,000,000 (thirty billion) watts.

net metering—An electric policy that allows consumers who own small sources of power, such as wind and solar, to get 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 Title 30 Vermont Statutes section 219a.

N-0 or **N-1** or **N-1-1**—The term N minus zero (or one or two) refers to the failure of important equipment. Although these terms sound complex, they are actually quite simple. "N" is the total number of components that the system relies on to operate properly. The number subtracted from N is the number of components that fail in a given scenario. Therefore, N-0 means that no components have failed and the system is in a normal condition. N-1 means that only one component has failed. N-1-1 means that two components have failed, which is generally worse than having only one fail (see also the definition of contingency above).

non-transmission alternative (NTA)—The use of a solutions other than transmission, such as generation or energy efficiency, to resolve a transmission reliability deficiency.

peaking resources—Generators that are expected to run only during peak load conditions, or when demand is near system capacity, or during some form of emergency.

power—The amount of electricity that is consumed ***(demand)*** or supplied at any given time.

pool transmission facility or facilities (PTF)—Generally speaking, any transmission facility operating at 69 kV or higher and connected to other transmission lines or transmission systems is considered PTF. PTF falls under the authority of ISO-New England and the construction of new PTF facilities is generally funded through ISO on a "load ratio share" basis among its member utilities, meaning funding is proportional to the amount of load served by each entity.

reconductoring—Replacing the conductor that carries the electricity. May also include poles and insulators from which the conductor is hung. Also referred to as rebuilding when a significant number of the poles need replacing.

reliability deficiency—An existing or projected future violation, before or after a contingency, of the applicable planning, design and/or operating criteria, with consideration given to the reliability and availability of the individual system elements.

renewable power source—Any power source that does not run on a finite fuel which will eventually run out, such as coal, oil, or natural gas. Renewable power sources include solar, wind and hydro generators, because sunlight, wind and running water will not run out. Generators that burn replaceable fuels also commonly qualify as renewable power sources. Examples include bio-diesel generators that run on crop-derived fuels and wood-burning generators.

right-of-way (ROW)—The long strip of property on which a transmission line is built. It may be owned by the utility or it may be an easement.

substation—A substation is a fenced-in area where several generators, transmission and/or distribution lines come together and are connected by various other equipment for purposes of switching, metering, or adjusting voltage by using transformers.

Sub-transmission—Sub-transmission lines are power lines that typically operate at a voltage of 34,000 to 70,000 volts and are generally below 100 kV.

transformer—A device that typically adjusts high-voltage to a lower voltage. Different voltages are used because higher voltages are better for moving power over a long distance, but lower voltages are better for using electricity in machinery and appliances. Transformers are commonly described by the two (or more) voltages that they connect, such as "115/13.8-kV," signifying a connection between 115-kV and 13.8-kV equipment or lines.

transmission—Transmission lines and transmission substations operate at high voltage and carry large amounts of electricity from centralized generation plants to lower voltage distribution lines and substations that supply local areas. Transmission lines use poles or structures, have long wire spans between poles and usually traverse fairly straight paths across large distances. Typical transmission voltages include 345-kV and 115 kV and generally all are above 100 kV.

transmission system reinforcements—Also referred to as Transmission system upgrades that are needed to address a reliability deficiency as defined in this plan and in the Docket 7081 MOU. Transmission line or substation equipment added to existing transmission infrastructure.

voltage—Voltage is much like water pressure in a system of pipes. If the pressure is too low, the pipes cannot carry enough water to satisfy the needs of those connected to them. If the voltage is too low, the electric system cannot carry enough electricity to satisfy the needs of those connected to it.

voltage collapse—A phenomenon whereby a series of events ultimately results in a blackout after a certain amount of time ranging from seconds to minutes.

voltage instability—A phenomenon whereby system operators cannot maintain acceptable system voltage given the tools at their disposal for a specific combination of load, generation and transmission. Voltage collapse may ensue.

9.2 Abbreviations

AC	Alternating current
BED	Burlington Electric Department
CEP	Comprehensive Energy Plan
CPG	Certificate of Public Good
DC	Direct current
DG	Distributed generation
DOE	US Department of Energy
DR	Demand Response
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FCM	Forward Capacity Market
GMP	Green Mountain Power
HQ	Hydro-Québec
HVDC	High voltage direct current
ISO-NE	ISO New England
MVAr	Megavar, mega-volt-ampere reactive
MW	Megawatts
MWh	Megawatt hours
NTA	Non-Transmission Alternative
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
OATT	Open-Access Transmission Tariff
PTF	Pool Transmission Facility
PSD	Vermont Public Service Department
PSNH	Public Service of New Hampshire
PUC	Vermont Public Utility Commission (formerly the Public Service Board
PV	Photovoltaic generation (solar)
RES	Renewable Energy Standard
SED	Stowe Electric Department
SPEED	Sustainably Priced Energy Enterprise Development
TO	Transmission owner
VEC	Vermont Electric Cooperative
VEIC	Vermont Energy Investment Corporation
VELCO	Vermont Electric Power Company
VJO	Highgate Vermont Joint Owners
VPPSA	Vermont Public Power Supply Authority
VY	Vermont Yankee
VSPC	Vermont System Planning Committee
WEC	Washington Electric Cooperative