2012 Vermont Long-Range Transmission Plan

July 1, 2012

VERMONT ELECTRIC VELCO POWER COMPANY, INC.

Message from VELCO CEO Chris Dutton

Dear Vermonter:

The power system has been called the most complex machine in the world. Every second of every day power supply must match power demand. Where demand exceeds local supply, transmission lines move power from its source to where it is needed, forming an interconnected regional and interregional electric grid that delivers the reliable power essential to modern life.

Vermont Electric Power Company (VELCO) constructs, owns and operates our state's electric transmission system and must maintain the integrity of this critical infrastructure. As part of that work, state law and Public Service Board Order require VELCO to plan for Vermont's 20-year transmission reliability needs, updating the plan every three years.

The 2012 Vermont Long-Range Transmission Plan is intended to ensure Vermonters have understandable information about where Vermont's electric transmission system may need future upgrades over the next 20 years and how those needs may be met through transmission projects or other alternatives. The Plan underwent six months of collaboration with the Vermont System Planning Committee, a group of public and utility representatives who play a key role in planning for Vermont's electric reliability. We then reached out to the general public for the input of other Vermonters who share an interest in future transmission system decisions. In April, May, and June, we met with citizens—local planners, homeowners, energy committee members, potential developers of generation, energy efficiency service provides, and any interested person—to hear their questions and comments, which have been incorporated into the final plan.

Much has changed since we filed our first plan in 2006, and the first three-year update in 2009. Perhaps most importantly, the regional grid operator, ISO-New England assumed primary responsibility for system reliability planning and the federal government established rigorous, binding standards of operation that carry significant financial penalties for non-compliance. These developments require that VELCO closely coordinate its planning work with that of ISO-New England by building this Plan on ISO's 2011 analysis of the Vermont/New Hampshire transmission system. We then supplemented that analysis to focus on the requirements of Vermont's long-range planning process to facilitate development of alternatives to transmission solutions.

Public feedback then helped us further refine the Plan into this final version. We hope Vermonters find the document to be a clear, understandable, informative discussion of a complex subject, and we invite continuing conversation about transmission reliability as a key part of Vermont's energy future.

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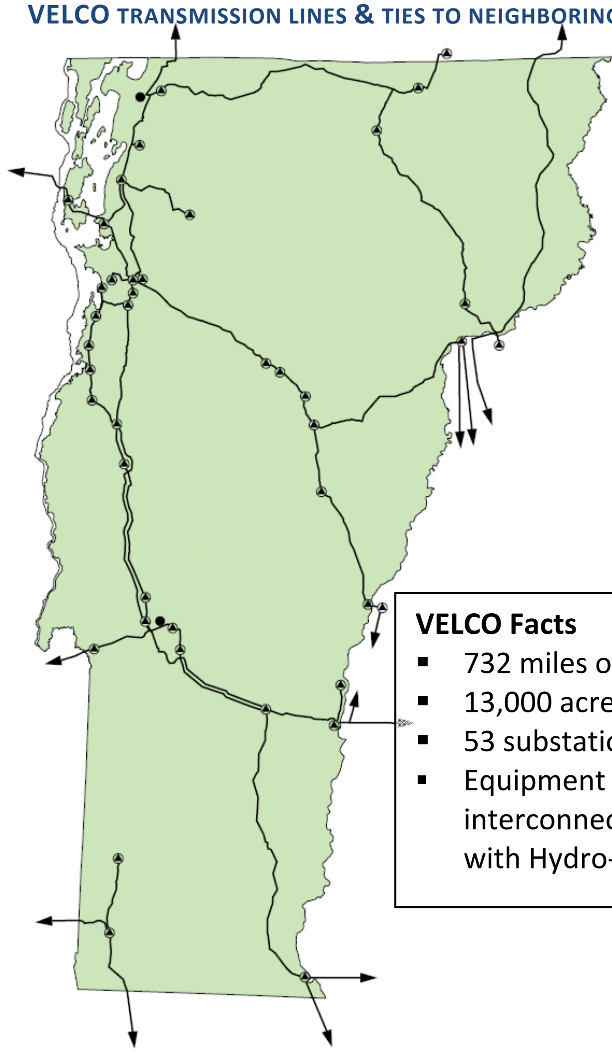
Introduction

Vermont law and Public Service Board (PSB) Order require VELCO to plan for Vermont's long-term electric transmission reliability, updating the plan every three years. The purpose of the plan is to ensure Vermonters have understandable information about where Vermont's electric transmission system may, with projected growth, need future upgrades and how those needs may be met through transmission projects or other alternatives. Ideally, all manner of interested people—local planners, homeowners, energy committees, potential developers of generation, energy efficiency service provides, and others—can look to the plan to learn what transmission projects might be required and how and where non-transmission alternatives, such as generation and energy efficiency, may contribute to meeting electric system needs.

VELCO's planning is an extensive and collaborative process. We are part of the New England 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 other transmission owners, 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 & TIES TO NEIGHBORING STATES & CANADA



VELCO Facts

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

The 2012 Vermont Long-Range Transmission Plan—the Plan—is the second three-year update of the Vermont 20-year plan, originally published in 2006 and updated in 2009. During these six years, much has changed. ISO-NE began operation as FERC's designated Regional Transmission Organization for New England in 2005. Since then, ISO-NE has continually refined and added staff to its regional planning process, and grown into the planning authority it was granted by FERC. Also during this period, stricter, binding 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 increasingly require that Vermont's planning process coordinate very closely with the regional planning work managed by ISO-NE. In 2011, ISO-NE completed a study of the Vermont/New Hampshire area—the VT/NH Needs Assessment—to identify areas of the transmission system in the two states that, if not addressed, will potentially fail to meet mandatory federal and regional reliability standards within the next 10 years. ISO-NE studied transmission solutions for the reliability concerns identified in the VT/NH analysis and, at VELCO's request, conducted a pilot non-transmission alternatives assessment to determine the size and location of alternative solutions that could avoid the need for a transmission solution.

Given ISO-NE's authority for regional planning, the Plan is based on ISO-NE's power system analysis. VELCO supplemented ISO-NE's study in a number of ways to meet the planning requirements of PSB Docket 7081 and to ensure the regional results were effectively translated to Vermont, which represents less than five percent of the region's electric demand.[1] VELCO refined ISO-NE's analysis of the Vermont transmission system to present the reliability issues in a way more consistent with the requirements of Vermont's long-range planning process in its objective of facilitating development of alternatives to transmission solutions. VELCO also conducted analysis beyond the regional study's 10-year horizon, analyzed the sub-transmission system[2], included the effects of budgeted energy efficiency beyond those historically taken into account in ISO-NE studies, and conducted a more extensive evaluation of non-transmission alternatives.

The results presented in this Plan show four regional groupings of reliability needs on Vermont's high-voltage, bulk electric system[3], which are presented beginning on page 19. Predominantly bulk system issues begin on page 30 and sub-system issues follow, on page 38. For each area, the Plan discusses potential non-transmission solutions and their feasibility. The Plan also reflects the considerable uncertainties in today's environment due to economic change and the effects of changing energy policy and production trends.

Issues addressed since the 2009 plan

The 2009 Plan identified 23 reliability issues on the Vermont transmission system, based on a forecast of demand for electricity prepared in 2008. The subsequent economic downturn, which slowed growth in demand, allowed us to defer some system upgrades and have ISO-NE confirm whether and when upgrades were needed. ISO's study, initiated in early 2010, now forms the foundation of this Plan update.

Some of the reliability deficiencies identified in the 2009 Plan were not dependent upon load growth and needed to be resolved in the near term. The table below shows how the reliability concerns identified in the 2009 Plan have been addressed or deferred. *(For comparison see page 21 and 26-27 of the 2009 Plan.)*

[1] Each New England utility funds a percentage of regional transmission projects based on its share of the total New England load.

[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.

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

DISPOSITION OF RELIABILITY ISSUES IDENTIFIED IN 2009 PLAN		
Name & No. Fig. 4-1, 2009 Plan	**Identified Deficiency**	**Solution Implemented**
Projects to address reliability issues identified in 2009 plan		
Middlebury (2)	Outage of the Middlebury transformer would cause a blackout in Middlebury area.	46 kV line between Weybridge & New Haven substations, 2011.
Georgia (1), Ascutney (6), Bennington (7)	Breaker failure or other events at these substations would cause low voltage and/or blackouts in a large area.	Change in configuration of these three substations to a "ring bus" layout. Permit application filed in 2011.
Blissville-Ascutney (8)	Outage of the Coolidge to W. Rutland 345 kV line would cause low voltages in a large area from Cavendish to Burlington.	Two 115 kV capacitor banks at West Rutland, 2011.
St. Johnsbury (10)	Outage of the St. Johnsbury transformer would cause a blackout in the St. Johnsbury area.	115 kV substation constructed at Lyndonville, 2010.
West Rutland-Coolidge (9)	High voltage under lower load levels.	345 kV shunt reactors (two at Coolidge and one at Vernon), end of 2012.
Project addressing issue new since 2009 plan		
Northern VT (not identified in 2009 Plan)	Outage of transformers in northern VT, aggravated by significant growth in the Jay area, would cause low voltages.	115 kV substation at Jay, permitted in 2011.
Deficiencies 11 to 23 were deferred pending the completion of the ISO-NE VT/NH 10-yr study.		

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 demand, called load. In areas where demand is greater than locally available supply the electrical network must be robust enough to accommodate the import of power from sources outside the area. Where supply is greater than local demand, the system must accommodate the export of power. 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 obligated to maintain the reliability of the high-voltage electric system based on binding federal and regional reliability standards. System planners use computer simulation software[4] that mathematically models the behaviors 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 employ specialized professional skill, such as forecasting electric usage. Still others rely on understanding evolving trends in the

[4] VELCO uses GE's "positive sequence load flow" or PSLF software.

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 the 2012 Plan.

Mandatory reliability standards

The criteria used to plan the electric system are set by the federal and regional reliability organizations, NERC, NPCC, and ISO-NE. These standards are the basis for the tests conducted in planning studies. A failure to comply with the NERC standards may result in significant fines, and more importantly, unresolved deficiencies can lead to blackouts affecting areas in and outside Vermont.

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 with:

1. All facilities in service (no contingencies or N-0).
2. A single element out of service (single contingency or N-1).
3. Multiple elements removed from service (due to a single contingency or a sequence of contingencies, i.e., N-1-1).

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 contingency 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 each scenario, if the software used to simulate the electric grid shows the system cannot maintain acceptable levels of power flow and voltage, a solution is required to resolve the reliability concern.

Study assumptions

System modeling manipulates three main parameters during a study: generation, the electrical network, and the electrical demand or load. The analysis models demand consistent with the results of a load forecast. Planning studies for this long range plan assume peak load conditions that occur during extreme weather using what is called a “90-10”forecast, meaning there is a 10 percent chance that the actual load will exceed the forecast.

The analysis models the electrical network in its expected configuration during the study horizon. New facilities and future system changes are modeled if they have received ISO-NE approval, which provides a level of certainty that the facility will be in service as planned.

All generators are modeled in service unless a basis exists to model them out of service. The capacity of intermittent generators is discounted based on historically validated expected performance during the summer peak hour. For instance, wind generation is discounted to 5 percent of its capacity, and hydro generation is discounted to 10 percent of its capacity. Peaking generators that can get to full output within 10 minutes were modeled at 80 percent of their combined total capacity based on historical performance in New England.

Lastly, the analysis begins by assuming two significant generation resources in the study area are out of service. This assumption is based on the sufficiently high and historically demonstrated expectation that any two resources can be unavailable due to planned outages as well as unforeseen events. For the sub-system analysis, the effect of local generation is more relevant. Therefore, instead of assuming two significant resources out of service, more attention was paid to local generator outages.

These study assumptions serve as the foundation for all long range plan studies in New England.

Assumptions regarding Plattsburgh-Sand Bar imports.

The system analysis for the 2012 Plan incorporates a major change in the study assumption about the flow of power from New York to Vermont over the Plattsburgh-Sand Bar transmission tie. Where past studies have always counted on those imports, the current analysis assumes that New York will no longer be able to provide support to Vermont when needed. System constraints in New York have led New York to request that studies assume zero megawatt (MW) will flow over the tie, and that, under certain conditions, Vermont will export to New York.

With this new assumption, the analysis shows weaker system performance, some transmission concerns emerge earlier, and the scale of transmission reinforcements needed to maintain reliability increases. The assumption of zero power from New York over this tie also increases the size of any non-transmission solutions needed to postpone the reliability problems.

VELCO, together with ISO-NE and other stakeholders, is urgently pursuing steps to ensure sufficient flow on the tie to postpone the need for a transmission solution in Vermont, but it is not yet clear whether these steps will yield a positive outcome. Some combination of transmission reinforcements and contractual or operating agreements between Vermont and New York entities will be required. First, transmission reinforcements in New York could physically allow imports from New York to be restored. In addition to the physical flow, a purchased power contract between New York and Vermont parties, or an operating agreement between New York Independent System Operator (NYISO) and ISO-NE may be needed. One concern is that NYISO may not agree to provide support to Vermont under emergency conditions. Due to these complexities and uncertainties with Vermont's ability to rely on power flow from New York, the transmission analysis was performed with the tie flow at 0 MW, and power flow levels consistent with the historical performance were evaluated as a non-transmission solution.

As a component of actions needed to restore the ability to rely on flows between New York and Vermont over this tie, VELCO is also considering installing equipment at Vermont's Sand Bar Substation to provide protection to the system, at an estimated cost of $4 million, as a preferred alternative to installing that equipment in New York.

ISO-NE Vermont/New Hampshire Needs Assessment the basis for the 2012 Plan update

As the Regional Transmission Organization for New England, ISO-NE manages the New England region's bulk electric power system, administers and operates the wholesale electricity market, administers the region's Open Access Transmission Tariff (OATT), and conducts regional transmission planning. This Plan is largely based on the regional 10-year analysis performed by the ISO-NE, supplemented to meet the requirements of the planning process approved by the PSB in Docket 7081. The adjustments include analysis of the transmission system beyond the 10-yr horizon, analysis of the sub-transmission system, inclusion of energy efficiency beyond ISO-NE's last currently scheduled auction for future power capacity, and a more extensive evaluation of non-transmission alternatives. The scope of the 10-year transmission analysis was prepared under the guidance of ISO-NE and in collaboration with the neighboring transmission owners, such as National Grid (NGRID) New York, NGRID New England and Public Service of New Hampshire (PSNH), and was reviewed by the ISO-NE Planning Advisory Committee (PAC). Through participation in the PAC, the public stakeholders and other interested parties can influence the ISO-NE regional study, have advance knowledge of deficiencies, and are able to propose alternative solutions that may include demand reduction and supply measures, all of which influence ISO-NE's overall Regional System Plan.

- 6.5 million households and businesses; population 14 million
- Over 300 generators
- 32,000 MW of total generation
- Over 8,000 miles of transmission lines
- 13 interconnections to electricity systems in New York and Canada
- 2,035 MW of demand-resources
- All-time peak demand of 28,130 MW, set on August 2, 2006
- More than 450 participants in the marketplace (those who generate, buy, sell, transport, and use wholesale electricity and implement demand resources)
- $9.1 billion total market value;
  $7.3 billion energy market
- More than $4.0 billion in transmission investment from 2002 through 2010 to enhance system reliability; approximately $5 billion planned over the next 10 years

  Eight major 345-kilovolt projects constructed; 6 more underway.

Key facts about New England's electric power system and wholesale electricity markets.

Source: ISO-NE 2011 Regional System Plan.

A note about the planning horizon: 10 years vs 20 years

The Docket 7081 planning process 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 are its conclusions due to uncertainties regarding predictions of load level, generation, system topology, 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 bulk of the analysis focuses on the 10-year period through 2021. 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 is consistent with the Docket 7081/Vermont System Planning Committee (VSPC) process.

Limitations in the scope of the Plan

This Plan may not include all transmission issues that must be addressed in the coming period. VELCO reached out to utilities during its analysis to identify all 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. 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 maintain a reliable grid. Sometimes these activities require significant projects, such as the current work to replace obsolete equipment at the Highgate converter discussed on page 15 and line rebuilds to replace aging equipment or maintain acceptable ground clearances. The Plan does not include such projects that are needed to maintain the existing system. Similarly, economic transmission—projects paid for by developers for the purpose of bringing power to markets—is generally beyond the scope of this reliability-focused plan except as discussed on pages 13.

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 with Vermont paying an approximate 4 percent share based on our share of New England load. Likewise, Vermont pays 4 percent of reliability upgrades elsewhere in New England. Facilities subject to regional cost sharing are called Pool Transmission Facilities or PTF. Most of the transmission reinforcement needs discussed in this Plan would likely be eligible for PTF treatment.

Regional sharing of funding for transmission projects has been present in New England for about a decade. Since 2008, through the creation of a regional energy market called the Forward Capacity Market, developers of generation and energy efficiency are compensated through regional funding for their capacity to contribute to meeting the region's future electric demand. These energy supplies may reduce the need for building transmission. Since the funding mechanisms are not identical and parity between transmission solutions and non-transmission alternatives has not yet been achieved, Vermont continues to advocate at the regional level for leveling the playing field between options to ensure cost-effective alternatives can compete effectively.

Forecasting demand

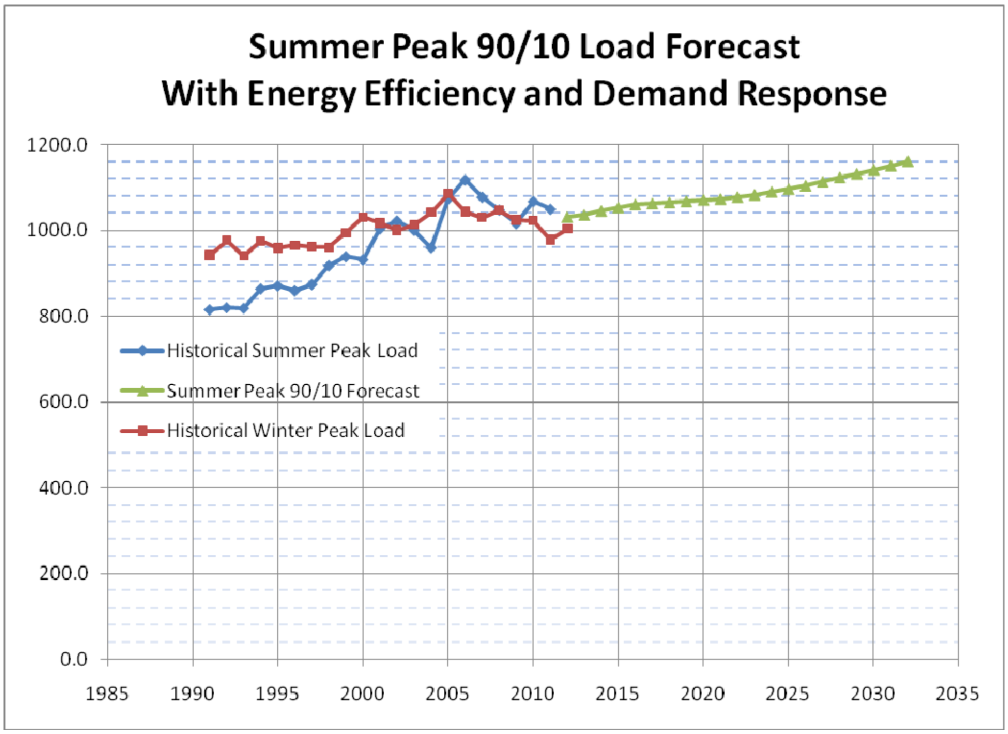
The forecast of future demand for electricity is a critical input in electric system planning. The forecast determines where and when system upgrades may be needed due to inadequate capacity.

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.

The forecast used in this plan

The following graph depicts the historical summer peak load and 20-year extreme weather, or 90/10, forecast adjusted for demand-side management (energy efficiency) effects and demand response. The forecast projects load levels in 2021 and 2031 of 1075 MW and 1160 MW, respectively. The growth rate during this 20-year period is approximately 0.5 percent, down from an historical growth rate of 1.5 percent over the last 20-year period. The forecast was used to determine the timing of reliability deficiencies in this 2012 Plan update

Forecasting for this Plan was completed in December 2011 by Itron, Inc., an energy firm that offers highly specialized consulting expertise in load forecasting, under contract with VELCO. In developing the forecast, Itron collaborated with the Vermont Energy Investment Corporation (VEIC) and the VSPC to incorporate the latest energy efficiency forecast—an update to Forecast 20 published by VEIC in September 2011 that accounts for 20-year, statewide energy efficiency funding approved by the PSB in August 2011. The Vermont Department of Public Service (DPS) led the collaboration on the forecast as part of the VSPC Energy Efficiency & Forecasting Subcommittee, which includes representatives of the distribution utilities and the public.



Although planners typically finalize their forecast at least one year before the planned completion date of the analysis, in this instance, VELCO sought to incorporate the latest energy efficiency information as well as the latest economic information. The volatility of current social, economic and environmental trends increases the importance of being as up-to-date as possible with the forecast.

Although VELCO contracted for its own, independent forecast, the analysis that serves as the basis for this Plan is the ISO-NE 2011 VT/NH Needs Assessment. ISO-NE conducts its own 10-year forecast, which was updated several times during the study process. Findings reported in this Plan include adjustments to ISO-NE's findings in light of VELCO's forecast, which incorporates a more fine-grained, Vermont-specific analysis.

PEAK DEMAND TRENDS

Transmission planning is based on peak electric demand, since infrastructure must be adequate to deliver power at the moment when usage is highest. Prior to 2002, Vermont electric demand peaked in the winter. Since 2002, Vermont, like the rest of New England, generally experiences its highest demand in the summer. The all-time highest demand occurred in summer 2006, and summer peaks have exceeded winter peaks every year since 2006 except in 2009 at the depth of the recession. The all-time Vermont summer peak of 1118 MW occurred in 2006. Following that milestone, the peak declined to as low as 1016 MW in 2009 due to the deep recession and unusually cool summers, but subsequently rebounded to 1068 MW in 2010 and 1050 MW in 2011 as the economy somewhat recovered. In 2010 and early 2011, economic projections assumed a fairly robust recovery.

Later in 2011, the economic projections were revised downward based on the expectation of a much slower recovery. The latest forecast projects slower load growth based on this slower economic recovery.

Accounting for energy efficiency and demand response in the forecast

The current forecast reflects the impact of increased public investment in energy efficiency. In August, 2011, the PSB approved 20-year budgets and savings targets for energy efficiency services funded through Vermont's energy efficiency charge on electric bills. For the Vermont forecast, Itron's challenge was to determine how much new energy efficiency to incorporate without double-counting energy efficiency that was already embedded in the forecast model. Through an analysis of historical loads and associated energy efficiency program expenditures, Itron determined that the load forecast should include about half the effects of energy efficiency program spending or $20 million per year, based on the conclusion that the base forecast already included approximately half the demand-side management effects. Following extensive collaboration with the VSPC Energy Efficiency & Forecasting Subcommittee, and consultation between Itron and VEIC, the analytical basis for this conclusion was fully explored leading up to its adoption for the current plan.

ISO-NE's 10-year analysis included the effects of the demand response that cleared the last forward capacity auction. The study included 41 MW of demand response in Vermont throughout the study period, distributed equally across the state. Currently, operators can call upon demand response as a capacity resource to manage requirements for operating reserves or to respond to abnormal system conditions. Beginning in 2016, demand response will be obligated to bid its price in the energy market, which may result in more frequent calls for participants to shut off their loads. It is unclear how demand response will react as a result of this market change and likely that certain demand response resources will leave the market, due to performance fatigue, financial disadvantages, or some other reason. Not being able to predict with reasonable certainty how demand response with vary in the future, the analysis assumes that demand response will remain relatively constant over time.

Inherent uncertainties in the timing of need for reliability solutions

System analysis determines at what level of electric demand a reliability problem occurs. Load forecasting predicts when that load level will be reached. The load forecast is based on factors such as the expected relationship between customer demand/behavior and the drivers of that demand, such as economic activity, price elasticity, population growth, new technology, efficiency, and weather. Load forecasters use various mathematical methods to represent these relationships. Depending on the various predictions of these drivers, the mathematical models provide a stream of load levels over the study horizon. Therefore, 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, and consequently the load forecast itself and, in turn, the timing of reliability concerns. Some of the other factors that contribute to uncertainties in the long term are summarized below.

- The trajectory of economic growth in Vermont and the region is uncertain, especially beyond ten years.
- Energy efficiency may be more difficult or expensive to obtain over the long run as easier and less costly load reductions have been achieved.
- New FERC and ISO-NE requirements for the treatment of 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. Although demand response was

modeled equally across the state, the location of the actual demand response may be different and therefore less effective than modeled in the planning studies.

- 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, or they may increase electric demand if they are charged during peak demand periods.
- Regional uncertainties may affect Vermont through its participation in the New England grid. Environmental regulations will likely have a large impact on the mix of generation resources in New England, and ISO-NE has previously projected a large amount of New England generation would potentially retire due to market forces and environmental concerns. New sources of energy, including imports and economic transmission, albeit regional resources, may affect the performance of the Vermont system, particularly for the period beyond ten years.
- Renewable energy and small-scale distributed generation have been expanding dramatically in the state recently. Amendments to Vermont statutes enacted in 2012 will greatly increase generation developed through the standard offer program over the next decade. Similarly, net metering is now easier to implement and costs of renewable energy, particularly solar, have decreased. Still, it is unknown just how fast these resources will be developed and whether transmission reinforcements will be required to accommodate greater levels of renewable resources.
- 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 regulation.

Additional assumptions affecting the system analysis

No "Economic" 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 sell power from one part of the system to another. Such projects, needed for purposes other than ensuring reliability, are categorized as economic transmission, and are financed by the project developer, not end-use customers.

While economic transmission can have an impact (positive or negative) on the reliability of the system, no economic project was assumed to have been completed during the Plan analysis because no economic project has yet progressed to the point that its completion is certain. With the exception of some sensitivities discussed below, the current plan addresses only transmission projects proposed to resolve system reliability deficiencies.

Imports from northern New York

During the 2009 analysis, a third party had proposed a project to increase the import capacity of the Plattsburgh-Sand Bar transmission tie to allow export of generation from northern New York to parts of New England. While the proposed imports were not modeled, the transmission facilities necessary to allow the projected power transfers were tested in both the 2009 and 2012 analyses to assess their potential system impacts. While in 2009 VELCO was optimistic about this project coming to fruition, today the project is significantly less certain. If realized, the project would eliminate some reliability concerns, but would likely require additional transmission reinforcements to accommodate the additional imports from New York. These negative impacts are not discussed as part of the Plan.

Expanded Hydro Québec generation

Hydro Québec (HQ) is developing its energy sector to support expected future load growth. Because its additional hydro power and wind energy will exceed Québec's near-term needs, HQ is seeking to export power to other parts of Canada and the United States.

During the 2009 plan, a consortium of New England transmission owners proposed to construct the Northern Pass Project, a high-voltage, direct current (HVDC) line and import power from Canada to New Hampshire. Analysis for both the 2009 and 2012 Plans showed that the project would have minimal effects on Vermont. If the project is augmented with a line from New Hampshire to Vermont, the need for one proposed Vermont transmission upgrade will be eliminated, however, the HVDC economic project is uncertain at this time.

In addition to the Northern Pass Project, other potential import paths could impact the Vermont system more directly. HQ may choose, for example, to export more power to Vermont through the present Highgate HVDC terminal or construct a new terminal on its own system near Highgate or near some other Vermont location. Such projects would provide reliability benefits to Vermont, and require reinforcement of the Vermont transmission system to accommodate the additional imports. Since no specific project is proposed, the Plan did not analyze potential HQ project impacts.

Renewable energy development

Renewable energy is in a period of significant expansion due to federal and state incentives and the decline of development costs. FERC Order 1000, issued in July 2011, establishes federal policy to increase renewable development by facilitating transmission reinforcements needed for significant renewable resources to connect to the grid. Transmission reinforcements affected by the new policies may range in scale from a large, inter-regional connection of Midwestern renewables to Northeast load centers, to a local project in Vermont to eliminate a constraint preventing renewable generation projects from moving forward. West of Vermont, developers are planning extensive wind generation in northern New York that will likely require transmission upgrades. Wind power is similarly constrained in northwest Maine. Routes through Vermont may be proposed to interconnect renewable generation, with potential reliability benefits to Vermont and needs for transmission reinforcement to provide adequate capacity. Since no specific project is proposed, the Plan does not analyze potential impacts of projects to deliver renewable energy to market.

Local resources

The following section discusses in-state generation and other resources that have an impact on the Vermont analysis.

Vermont Yankee

The license for the Vermont Yankee (VY) nuclear plant is scheduled to expire in 2012. In light of litigation pending at the time of the analysis, system performance was evaluated in two ways: assuming both its retirement and its continued operation.

Consistent with the 2009 Plan[5], the 2012 Plan reveals that no new transmission facilities would be needed in Vermont if Vermont Yankee is retired. Several reliability issues will emerge on the Vermont system with and without continued operation of the plant. With Vermont Yankee in service, some upgrades will be needed near

[5] See 2009 Vermont Long-Range Transmission Plan, page 6.

the plant sooner than with the plant retired, although the scale of those upgrades is the same whether or not the plant is in service. The scale of non-transmission alternatives needed to avoid transmission upgrades would need to be larger with VY in service than with the plant retired. Similarly, with Vermont Yankee retired, some upgrades will be needed earlier.

Some of the reliability concerns aggravated by VY retirement were identified in the 2009 plan and are being addressed. To address these reliability issues, VELCO installed 115 kV capacitor banks at West Rutland in December 2011, and 345 kV shunt reactors are expected to be installed at Coolidge and Vernon before the end of 2012.

The Highgate Converter

The Highgate Converter is the point at which energy flows from HQ to Vermont's electric grid. HQ and the Vermont utilities recently renewed the contract for this power, effectively establishing that power deliveries will continue over the tie for the foreseeable future. The converter can carry the full contracted amount during all hours of the year except periods of high demand that can affect the Hydro Québec system. During the summer, the converter has been able to import power close to its capacity, but unless the HQ system is upgraded, the system capacity will gradually decrease due to load growth-related voltage concerns on HQ's system. To ensure the converter continues to operate reliably, VELCO, at the direction of the Vermont Joint Owners, is replacing obsolete equipment, including the cooling and control systems. This refurbishment project in itself will not improve the ability of the converter to import the full contracted amount, which will be achieved by HQ upgrading its transmission system by 2014.

As described on page 7, transmission planners begin testing the system by assuming that two significant resources are out of service, simulating conditions that are not unusual in system operation. Although Highgate is a significant resource supplying Vermont load, Vermont stakeholders proposed, and ISO-NE agreed, not to include Highgate among the two large resources assumed unavailable in long-term needs assessments prior to testing the impact of additional events or contingencies. This assumption may be overly optimistic, posing some risk of customer-impacting events or the need to run costly generation in the event of a failure.

Vermont base load power

Vermont has very little "base load" generation of its own—power plants that produce energy at a constant rate and are used to meet the state's continuous energy demand. The largest base load generation resource other than Vermont Yankee is the 50 MW McNeil wood burning unit in Burlington. Other base load plants are rated 20 MW or less and total approximately 30 MW.

Normally, transmission planners test the system by assuming two significant resources are out of service (see discussion on page 7). In Vermont's case, McNeil alone was modeled out of service. This fact is important for two reasons. First, in assuming only one resource out of service, the analysis of Vermont's system is founded on a more optimistic base case than planners normally apply. Second, a new generator in Vermont with a capacity greater than 25 MW may benefit the system by helping to serve Vermont load, but such a generator will provide no reliability benefit because it will become the second significant resource to be assumed out of service. For this reason, some generation projects under discussion are modeling multiple 25 MW turbines so, even with one assumed out, such a project could still be assumed available to provide reliability benefits consistent with normal planning standards.

Vermont peaking power

Study assumptions related to Vermont's peaking power capacity are more optimistic than warranted by historical data on account of power plant performance and condition. Fifteen Vermont generators with a capacity of approximately 130 MW fall in the category of 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 system emergency. The system analysis considered the 130 MW suitable for providing 10-minute reserves—resources able to get to full output within 10 minutes—and assumed 80 percent of those 130 MW would be turned on following an event or contingency meaning that 20 percent would fail to start or run when needed.

Historical data show that three of the peaking units (13 MW total) have not run during the last five summer peak hours, and four other units, for a total of 15 MW, have not run during the last four summer peak hours. Two of the units (6 MW) have been unavailable since the fall of 2009, and two other units (16 MW) have been unavailable since the fall of 2010. The Vermont peaking units for the past ten years have performed well below the 80 percent assumption during emergency conditions. During the 2011 summer peak hour, only 65 MW (50 percent) of generation came on line, even on a day when customers with interruptible load contracts were disconnected to address a capacity deficiency in New England. Similarly, in 2006 during the Vermont all-time summer peak when interruptible load was also disconnected, only 75 MW came on line.

Proposed generation projects in the ISO-NE interconnection queue

Vermont has seen less development of larger generation projects than other parts of New England, continuing the state's heavy reliance on the transmission system to deliver power from neighboring states to Vermont load pockets. Increasing development activity in recent years has focused on constructing small generation projects with a capacity of less than 100 MW.

The 2012 analysis takes into account any new generators that have a capacity supply obligation, either through the ISO-NE Forward Capacity Market or through a bilateral contract. Conceptual or proposed projects were not considered. Historically many proposed generation projects ultimately withdrew their interconnection requests due to financial difficulties, permitting, local opposition, inability to find customers and other factors. Nearly 235 MW of proposed generation in the ISO-NE generation interconnection queue are located in Vermont, but the majority consists of wind generation, which provides reliability benefits up to 5 percent of its maximum capacity. About 17 percent—40 MW—is beneficial to the system due to its location, size and fuel source. This amount was considered as part of a non-transmission solution to the reliability issues identified in the 2012 system analysis. Planned generation projects that have received ISO-NE approval and have a capacity supply obligation in the market were modeled in service.

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 2011 Vermont Comprehensive Energy Plan reports that more than 13 MW of net metering systems have received certificates of public good (CPGs) [6], and 50 MW of projects have been approved to receive the Standard Offer through the SPEED Program[7]. The legislature in 2012 adopted proposals that further expand state incentives for small-scale renewables. Because

[6] Comprehensive Energy Plan, Volume 2, page 70, http://www.vtenergyplan.vermont.gov/sites/cep/files/2011%20CEP_Volume%202.pdf.

[7] SPEED stands for Sustainably Priced Energy Enterprise Development program, For more information see vermontspeed.com .

these resources are small and located on the distribution system, they are modeled as reductions in the load similar to energy efficiency effects. Larger SPEED projects, such as Sheffield, are modeled explicitly.

Two programs—net metering[8] and the SPEED program—are assuring a market for the output of small renewables. Vermont utilities are currently required to buy the yearly output from net metered customers at $0.2/KWh up to a ceiling of 4 percent of the state's load. The SPEED Program requires utilities to purchase in-state renewable energy at a predetermined price established by the PSB. The program's objective is to supply all new energy usage growth from 2005 to 2012, and to supply 20 percent of the state's energy by 2017. The program easily met an initial goal to serve five percent of Vermont's 2005 energy needs (287,421 MWh) through large projects, such as Sheffield Wind, which alone contributed more than 100,000 MWh. A number of other large SPEED projects are under development including wind farms at Deerfield, Georgia Mountain and Kingdom Community Wind in Lowell.

In 2009, the program was oversubscribed for its 50 MW cap, and a large number of interconnection requests were set aside in a queue that contains approximately 140 MW of proposed generation, almost exclusively solar, until such time as the 50 MW ceiling is lifted. As of late 2011, approximately 8 MW of SPEED resources are in service, mostly solar and methane with another 17 MW starting construction in 2012. Legislation enacted in 2012 will gradually increase the cap on SPEED standard offer programs to 127.5 MW over the next decade.

Further factors are encouraging the development of in-state renewables including Vermont Small Scale Renewable Energy Program, the Clean Energy Development Fund, and green pricing programs. In addition, multiple organizational resources, such as Renewable Energy Vermont and the Biomass Energy Resource Center, provide support and advocacy for one or more types of renewable energy resources. Many of the more than 60 active local energy committees in Vermont communities are considering community-based renewable development programs.

Equivalency Principles

This Plan is designed to help fulfill VELCO's legal requirement to provide full, fair and timely consideration of cost effective non-transmission alternatives to meeting Vermont's transmission reliability needs. To facilitate consideration of non-transmission alternatives, VELCO's Plan must identify the performance criteria that a non-transmission alternative would need to meet for equivalency to a transmission solution. The following section describes the criteria for non-transmission alternatives to effectively address a given reliability deficiency.

- ***Location.*** While generation and energy efficiency have benefits wherever they are located, to resolve a reliability issue, a non-transmission solution must be located within the area affected by the deficiency. Even within the affected area, some locations are more useful than others. The farther a single, non-transmission resource is located electrically from the problem, the less its effectiveness and, therefore, the greater the output capacity needed to be suitable.
- ***Capacity.*** The amount of generation needed to solve a particular reliability problem may be greater than the size of the deficiency because power flow leaves the generator via all transmission elements, not just on the overloaded line or transformer.

[8] 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 30 V.S.A. § 219a.

- ***Availability.*** An effective non-transmission alternative must be present and in-service when the problem occurs. The most significant challenge to deploying non-transmission alternatives is the need for the solution to be available at the time when the capacity deficiency occurs. For example, an energy efficiency measure that targets air conditioning is not appropriate to address a system concern that occurs in the winter, and a measure that targets residential lighting is not appropriate for a system concern that tends to occur on summer afternoons. A generator must be "on-line," and customer load enrolled in a demand response program must be "off line," when the transmission system deficiency arises for these resources to be effective alternatives to a transmission reinforcement. In addition, the variations that occur in system voltage, frequency and power flow during events or outages can cause protective devices to automatically disconnect local generation from the transmission system to avoid potential damage. An effective generation alternative must include design features that ensure it is able to operate under such stressed system conditions.
- ***Longevity.*** The size of a transmission system upgrade typically resolves a given reliability deficiency with a margin to spare to ensure effectiveness over the life of the infrastructure. While a non-transmission alternative may mitigate an immediate reliability concern, it does not remain effective for the same duration as does the transmission alternative as demand continues to grow. Evaluation of equivalence requires economic evaluation of savings from deferring transmission, as well as practical evaluation of how long an alternative will be effective as compared with the transmission solution.

Solving multiple issues. While not an equivalency criterion, it is worth noting that some non-transmission alternatives may effectively address more than one deficiency. A demand response program, or generator deployed on a sub-transmission network, may help address a deficiency that involves loss of the transformer connecting the sub-transmission network to the transmission system, or loss of local portions of the transmission system.

Transmission Results

The following section presents the findings of the ISO-NE VT/NH Needs Assessment, supplemented with additional analysis and the updated load forecast by VELCO.

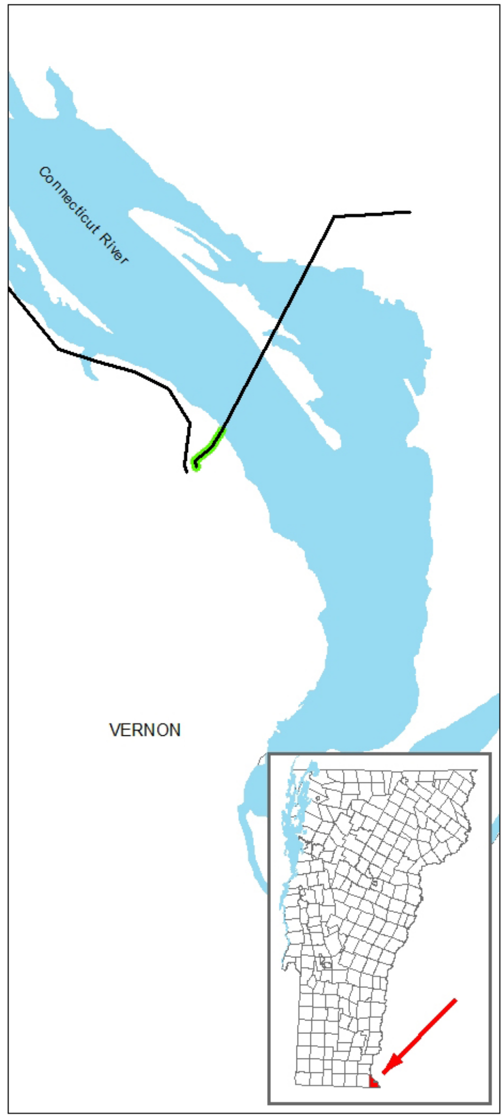
Bulk System Issues

This section describes reliability issues 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. The VT/NH Needs Assessment identified four regional groupings of bulk system reliability issues that are presented beginning on page 20. The following table summarizes the bulk transmission system issues identified in the study for quick reference.

SUMMARY OF BULK SYSTEM REGIONAL GROUPING & TRANSMISSION SOLUTIONS	PROPOSED LEAD & AFFECTED DISTRIBUTION UTILITIES	ESTIMATED TRANSMISSION PROJECT COST & (VT SHARE)[9]	SCREENED IN OR OUT OF FULL NTA ANALYSIS
Southeast Vermont • Rebuilding the Vermont portion of the Vernon to Northfield 345 kV line, as part of a larger VT/NH/MA set of upgrades.	*Lead*: GMP[10] *Affected*: All VT	$6M ($.24K)	Out
Connecticut River Valley • Construction of a second 115 kV line between Coolidge and Ascutney.	*Lead*: GMP Affected: All VT	$93M ($3.7M)	Out
Central Vermont • Construction of a second 345 kV line between Coolidge and West Rutland. •	*Lead*: GMP *Affected*: All VT	$157M ($6.3M)	In
Northwest Vermont • Rebuilding the West Rutland to Middlebury 115 kV line • Rebuilding the New Haven to Williston 115 kV line • Rebuilding the Williston to Tafts Corner 115 kV line	*Lead*: GMP *Affected*: All VT	$221M ($8.8M)	In

[9] Project cost estimates include a 50 percent contingency (cost adder) to account for unknown factors that can affect project costs. Costs associated with line additions also include substation expansion costs. Estimated Vermont share assumes all project elements are treated as pool transmission facilities (PTF) by ISO-NE, and that Vermont’s share is 4% of the region.

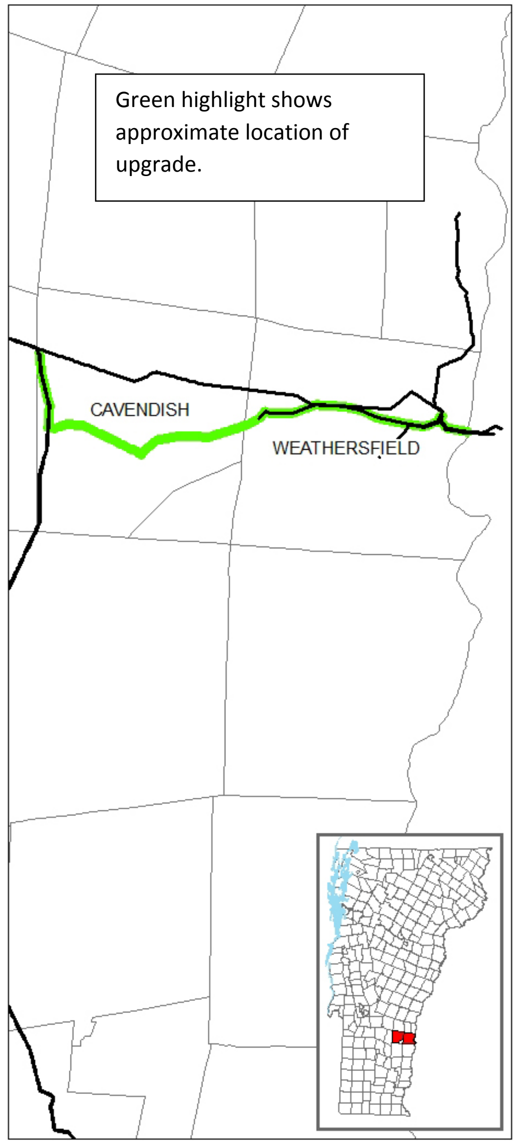
[10] The merger of GMP and CVPS was approved just prior to Plan publication. Past activities refer to CVPS and GMP. For future actions, references to CVPS as a lead or affected utility have been changed to GMP throughout.

<table>
<tr><th colspan="3">REGIONAL GROUPING 1: SOUTHEAST VERMONT</th></tr>
<tr><td>Location</td><td>Vernon to Northfield 345 kV line (Vernon, VT, to Massachusetts)</td><td rowspan="3">
</td></tr>
<tr><td>Analysis</td><td>Line exceeded its current carrying capacity</td></tr>
<tr><td>When deficiency occurs</td><td>This is an interstate problem that arises when regional power flows from western New England (Vermont, western Massachusetts and Connecticut) to eastern New England (New Hampshire, Maine, eastern Massachusetts and Rhode Island,) and from New Hampshire to Maine. The overloads could occur when more than one element is out of service (N-1-1 conditions.) The overload is largely affected by power transfers from Massachusetts to Vermont and primarily to New Hampshire. Vermont Yankee can reduce or aggravate the overload depending on whether it is running or out of service, respectively.</td></tr>
<tr><td>Preferred transmission solution</td><td colspan="2">Rebuilding the Vermont portion of the Vernon to Northfield 345 kV line.
Estimated project cost: $6M. (Approx. VT share if all project costs are considered PTF: $.24M.)</td></tr>
<tr><td>In service date</td><td colspan="2">Summer 2014 (assuming typical design, public outreach, permitting and construction process timing, and that VY does retire).</td></tr>
<tr><td>Status</td><td colspan="2">Various transmission alternatives were evaluated as part of the ISO-NE 10-yr study, and this solution was selected as the preferred transmission solution. Screened out of further non-transmission analysis using VSPC NTA screening tool. No additional analysis of transmission or non-transmission alternatives is planned and permitting will proceed in 2012, assuming VY retires as scheduled.</td></tr>
</table>

<table>
<tr><td rowspan="2">Critical load level & need timing</td><td>Vermont
With VY: 1100 MW</td><td>New England
With VY: 29800 MW</td><td>Est. timing of need
2026</td></tr>
<tr><td>Without VY: TBD</td><td>Without VY: TBD</td><td>TBD[11]</td></tr>
<tr><td>Proposed lead & affected utilities</td><td colspan="3">Lead utility: GMP
Affected utilities: All Vermont distribution utilities
Regional: National Grid and Northeast Utilities[12]</td></tr>
<tr><td>NTA screening</td><td colspan="3">Q 1: Is the proposed project’s cost expected to exceed $2 million?
A 1: Yes
Q 2: Could elimination or deferral of all or part of the upgrade be accomplished through the use of non-transmission alternatives?
A 2: No, this overload is primarily affected by load in New Hampshire and regional power transfers and cannot effectively be influenced by reductions in Vermont load. Q 3: Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $1,000,000?
A 3: Not applicable—screened out by Q2.</td></tr>
<tr><td>Equivalency</td><td colspan="3">The reliability deficiencies in the southeast region occur as a result of an outage event after one transmission or generation facility is already out of service. A non-transmission solution would not need to be in service under normal conditions, but would need to be on line after a transmission or generation facility is out of service. A non-transmission solution would need to be located east of the Vermont Yankee substation in Vernon, VT, or in New Hampshire.</td></tr>
</table>

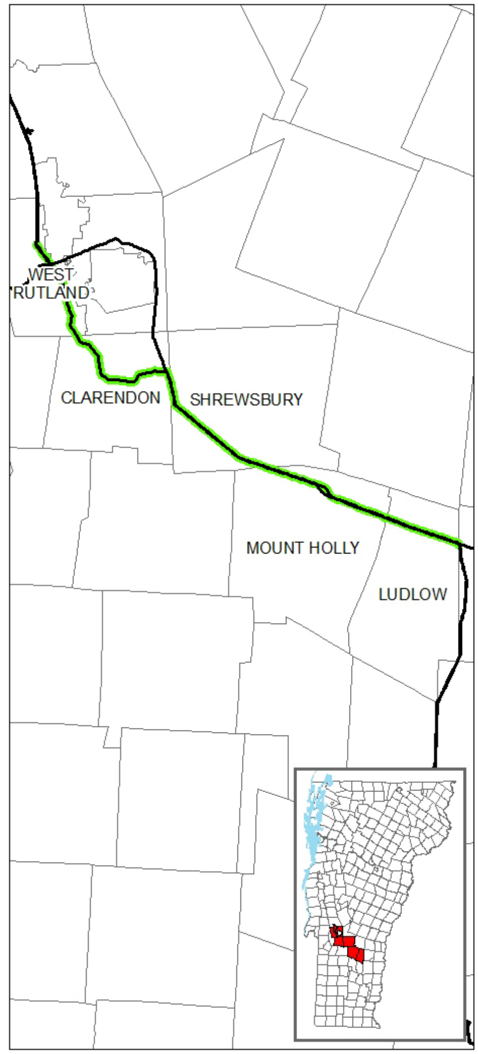
[11] ISO-NE has accepted the VY request to cease participation in the Forward Capacity Market for some period. The litigation regarding VY’s continued operation in Vermont is not yet resolve.

[12] The Plan identifies regional utilities outside Vermont whose systems are affected by a reliability issue. While Vermont utilities will need to coordinate with these non-Vermont utilities on solutions – directly and in the context of ISO-NE regional planning– these utilities are not subject to Vermont regulatory requirements and, as such, are not “affected utilities” in the context of Docket 7081 requirements.

<table>
<tr><th colspan="3">REGIONAL GROUPING 2: CONNECTICUT RIVER VALLEY</th></tr>
<tr><td>Location</td><td>Coolidge to Ascutney 115 kV line (through Cavendish and Weathersfield)</td><td rowspan="3">
</td></tr>
<tr><td>Analysis</td><td>Line exceeded its current carrying capacity, and voltages were below acceptable limits in a subarea including the Chelsea, Bellows Falls, and North Road 115 kV substations.</td></tr>
<tr><td>When deficiency occurs</td><td>This is an interstate problem that arises when regional power flows from western New England (Vermont, western Massachusetts and Connecticut) to eastern New England (New Hampshire, Maine, eastern Massachusetts and Rhode Island.) Overload occurs under all-lines-in conditions (no contingencies or N-0 conditions), a single contingency that may remove one or more elements from service (N-1 conditions) and two succeeding contingencies (N-1-1 conditions.) The overload is largely affected by power transfers from generation in Massachusetts and Vermont supplying New Hampshire load. Vermont Yankee can aggravate or reduce the overload depending on whether it is running or out of service, respectively.</td></tr>
<tr><td>Preferred transmission solution</td><td colspan="2">Construction of a second 115 kV line between Coolidge and Ascutney.
Estimated cost: $93M which includes substation costs. (Approx. VT share if all project costs are considered PTF: $3.7M.)</td></tr>
<tr><td>In service date</td><td colspan="2">Summer 2016 (assuming typical design, public outreach, permitting and construction process timing).</td></tr>
<tr><td>Status</td><td colspan="2">Solution selected as the preferred transmission alternative in ISO-NE 10-year study. Screened out using VSPC NTA screening tool. No further analysis of transmission or non-transmission alternatives is planned and permitting will proceed in 2012.</td></tr>
</table>

<table>
<tr><td rowspan="2">Critical load level & need timing</td><td colspan="2">Vermont
With VY: 880 MW</td><td colspan="3">New England
With VY: 23600 MW</td><td colspan="2">Est. timing of need
Past</td></tr>
<tr><td colspan="2">Without VY: 970 MW</td><td colspan="3">Without VY: 26000 MW</td><td colspan="2">Past</td></tr>
<tr><td rowspan="3">Reliability gap in MW[13]</td><td></td><td>Location</td><td>PV20@0
VT@1060</td><td>PV20@0
VT@1100</td><td>PV20@0
VT@1160</td><td>PV20@70
VT@1060</td><td>PV20@70
VT@1100</td><td>PV20@70
VT@1160</td></tr>
<tr><td>VY in service</td><td>Ascutney Tap</td><td>213</td><td>263</td><td>310</td><td>209</td><td>258</td><td>306</td></tr>
<tr><td>VY out of service</td><td>Ascutney Tap</td><td>115</td><td>166</td><td>212</td><td>110</td><td>161</td><td>208</td></tr>
<tr><td>Proposed lead & affected utilities</td><td colspan="8">Lead utility: GMP
Affected utilities: All Vermont distribution utilities
Regional: National Grid and Northeast Utilities</td></tr>
<tr><td>NTA screening</td><td colspan="8">Q 1: Is the proposed project's cost expected to exceed $2 million?
A 1: Yes
Q 2: Could elimination or deferral of all or part of the upgrade be accomplished through the use of non-transmission alternatives?
A 2: No. This overload is primarily affected by load in New Hampshire and regional power transfers and cannot effectively be influenced by reductions in Vermont load. Analysis showed it would require more than 200 MW of generation located at the Ascutney tap to postpone the transmission solution. Generation of this size cannot be supported by the current fuel infrastructure in Vermont and would exceed the cost of the transmission solution.
Q 3: Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $1,000,000?
A 3: Not applicable—screened out by Q2.</td></tr>
<tr><td>Equivalency</td><td colspan="8">The reliability deficiencies in the Connecticut River region occur under normal conditions, with all transmission facilities in service, or as a result of a single outage event. A non-transmission solution would need to be in service during all hours where the load level exceeds the critical load level. In this case, the non-transmission solution would need to be on line when the Vermont load is at or above 880 MW, a proxy for the relevant New Hampshire load level that creates this reliability concern. A non-transmission solution would need to be located east of the Ascutney substation (Weathersfield, VT, or New Hampshire).</td></tr>
</table>

[13] Reliability gap associated with reliability concerns at various load levels and PV20 NY to VT import assumptions. The reliability gap is the effective amount of demand or generation resource that would be required to resolve the reliability concern. The amount of the gap associated with each reliability deficiency will vary depending on the location of the resource and the completion of transmission reinforcements

REGIONAL GROUPING 3: CENTRAL VERMONT		
Location	• Blissville, West Rutland, North Rutland, Cold River & Coolidge 115 kV substations. • Coolidge 345/115 kV autotransformer (in Cavendish). • 115 kV lines from Coolidge to Cold River to North Rutland to West Rutland (through Ludlow, Mount Holly, Shrewsbury, Clarendon, Rutland and West Rutland).	
Analysis	Voltages were below acceptable limits in a subarea including the Blissville, West Rutland, North Rutland, Cold River and Coolidge 115 kV substations. Several transmission facilities overloaded, including the Coolidge 345/115 kV autotransformer, and the 115 kV lines from Coolidge to Cold River to North Rutland to West Rutland.	
When deficiency occurs	The overloads could occur when more than one element is out of service (N-1-1 conditions), particularly when power is flowing from west to east regionally. Vermont Yankee can aggravate or reduce the overload depending on whether it is running or out of service, respectively.	
Preferred transmission solution	Construction of a second 345 kV line between Coolidge and West Rutland with a 60 MVAr 345 kV variable shunt reactor at West Rutland[14]. Estimated cost: $157M, which includes substation costs. (Approx. VT share if all project costs are considered PTF: $6.3M.)	
In service date	Summer 2016 (assuming typical design, public outreach, permitting and construction process timing).	
Status	Various transmission alternatives were evaluated as part of the ISO-NE 10-year study, and this solution was selected as the preferred transmission solution. NTA solutions may be viable and are currently under study.	

[14] Assuming the reliability concern cannot be addressed by a non-transmission alternative, such as increasing imports from New York across the PV-20 line

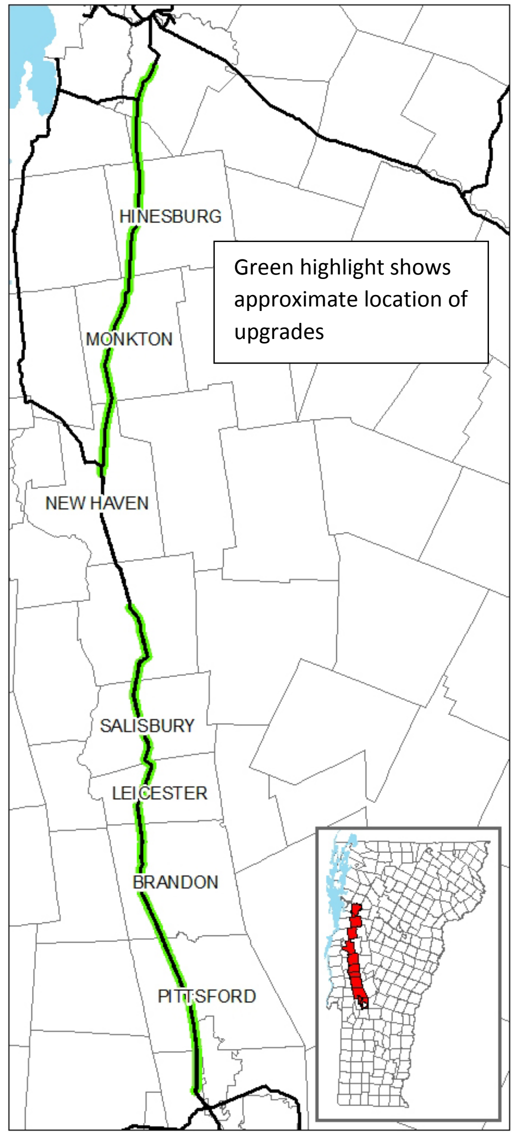
Critical load level & timing of need	Transmission element	Vermont	New England	Est. timing of need
	With VY in service:			
	Coolidge autotransformer	1050 MW	28200	2015
	Coolidge-Cold River 115 kV line	1010 MW	27100	Past
	Cold River-North Rutland 115 kV line	1045 MW	28000	2014
	North Rutland-West Rutland 115 kV line	1110 MW	29800	2027
	Without VY:			
	Coolidge autotransformer	1110 MW	29800	2027
	Coolidge-Cold River 115 kV line	1020 MW	27400	Past
	Cold River-North Rutland 115 kV line	1055 MW	28300	2016
	North Rutland-West Rutland 115 kV line	1130 MW	31400	2029

Reliability gap in MW with VY in service		Locations	PV20@0 VT@1060	PV20@0 VT@1100	PV20@0 VT@1160	PV20@70 VT@1060	PV20@70 VT@1100	PV20@70 VT@1160
	Coolidge autotransformer	W Rutlnd	11	82	175	0	13	100
		W Rutlnd & Asct Tp	11 & 0	45 & 44	58 & 155	0 & 0	0 & 14	51 & 67
	Coolidge-Cold River 115 kV line	Essex	47	82	144	0	0	60
		W Rutlnd	37	60	113	0	0	51
		Essex & W Rutlnd	0 & 37	23 & 45	69 & 58	0 & 0	0 & 0	0 & 51
	Cold River-North Rutland 115 kV line	Essex	19	48	113	0	0	30
		W Rutlnd	11	36	86	0	0	23
		Essex & W Rutlnd	0 & 11	23 & 19	69 & 31	0 & 0	0 & 0	0 & 23
	North Rutland-West Rutland 115 kV line	Essex	0	0	45	0	0	0
		W Rutlnd	0	0	37	0	0	0
		Essex & W Rutlnd	0 & 0	0 & 0	45 & 0	0 & 0	0 & 0	0 & 0

Reliability gap in MW with VY out of service		Locations	PV20@0 VT@1060	PV20@0 VT@1100	PV20@0 VT@1160	PV20@70 VT@1060	PV20@70 VT@1100	PV20@70 VT@1160
	Coolidge autotransformer	W Rutlnd	0	0	82	0	0	8
		W Rutlnd & Asct Tp	0 & 0	0 & 0	53 & 35	0 & 0	0 & 0	8 & 0
	Coolidge-Cold River 115 kV line	Essex	33	69	129	0	0	42
		W Rutlnd	23	53	99	0	0	34
		Essex & W Rutlnd	0 & 23	10 & 43	58 & 53	0 & 0	0 & 0	0 & 34
	Cold River-North Rutland 115 kV line	Essex	6	39	95	0	0	9
		W Rutlnd	4	29	77	0	0	7
		Essex & W Rutlnd	0 & 4	10 & 22	58 & 33	0 & 0	0 & 0	0 & 7
	North Rutland-West Rutland 115 kV line	Essex	0	0	33	0	0	0
		W Rutlnd	0	0	23	0	0	0
		Essex & W Rutlnd	0 & 0	0 & 0	33 & 0	0 & 0	0 & 0	0 & 0

Proposed affected & lead utilities	**Lead utility:** GMP **Affected utilities:** All Vermont distribution utilities **Interregional:** New York utilities
NTA screening	*Q 1: Is the proposed project's cost expected to exceed $2 million?* A 1: Yes *Q 2: Could elimination or deferral of all or part of the upgrade be accomplished through the use of non-transmission alternatives?* A 2: Yes *Q 3: Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $1,000,000?* A 3: Yes. *Discussion*: Although non-transmission alternatives are a viable means to address this group of deficiencies, obstacles may preclude their implementation. The amount of load reduction needed is too large for energy efficiency to be implemented in time. Generation additions may be viable options, particularly as part of a hybrid solution that includes transmission reinforcement and/or additional power delivery commitments from New York. Depending on the amount of generation needed, the current fuel infrastructure in Vermont may not be able to support the needed generation. A more detailed analysis is being conducted to determine whether the cost of generation would exceed the cost of transmission and whether non-transmission alternatives are feasible.
Equivalency	The reliability deficiencies in the Central Vermont region occur as a result of an outage event after one transmission facility is already out of service. A non-transmission solution would not need to be in service under normal conditions, but would need to be on line at or above a Vermont load level of 1010 MW after a transmission facility is out of service. A non-transmission solution would need to be located west and north of the North Rutland substation to be effective.

REGIONAL GROUPING 4: NORTHWEST VERMONT



Location	Large area of northwest Vermont from Georgia to West Rutland and east to Williamstown.
Analysis	Voltages were below acceptable limits in a subarea bordered by the Georgia, Sand Bar (Milton), West Rutland and Granite 115 kV substations. Several transmission facilities overloaded, including the West Rutland to Florence to Middlebury 115 kV line, the New Haven to Williston 115 kV line, and the Williston to Tafts Corner line. More line sections along this path will overload with load growth.
When deficiency occurs	The overloads could occur when more than one element is out of service (N-1-1 conditions), particularly when power is flowing from west to east regionally. Vermont Yankee can aggravate or reduce the overload depending on whether it is running or out of service, respectively.
Preferred transmission solution	Rebuild overloaded lines in the Northwest Vermont subarea Estimated cost: $221M. (Approx. VT share if all project costs are considered PTF: $8.8M.)
In service date	The in-service date for these upgrades is unknown because the timing of need exceeds the 10-year horizon based on the current forecast. Factors that affect the timing are load growth, addition or retirement of generation, amount of load reduction through energy efficiency, and the ability to import more power from the north. Additional analysis will inform decision-making later in 2012.
Status	Various transmission alternatives were evaluated as part of the ISO-NE 10-year study, and this solution was selected as the preferred transmission solution. NTA solutions may be viable and are currently under study.

Critical load level & timing of need	*Transmission element*	*Vermont*	*New England*	*Est. timing of need*
	VY in service:			
	West Rutland-Florence 115 kV line	1105 MW	29600	2026
	Florence-Middlebury 115 kV line	1080 MW	29000	2023
	New Haven-Williston 115 kV line	1105 MW	29600	2026
	Williston-Tafts Corner 115 kV line	1105 MW	29600	2026
	VY out of service:			
	West Rutland-Florence 115 kV line	1110 MW	29800	2027
	Florence-Middlebury 115 kV line	1090 MW	29200	2024
	New Haven-Williston 115 kV line	1110 MW	29800	2027
	Williston-Tafts Corner 115 kV line	1110 MW	29800	2027

Reliability gap in MW with VY in service	VY in service	Locations	PV20@0 VT@1060	PV20@0 VT@1100	PV20@0 VT@1160	PV20@70 VT@1060	PV20@70 VT@1100	PV20@70 VT@1160
	West Rutland-Florence 115 kV line	Essex	0	0	52	0	0	0
		Highgate	0	0	67	0	0	0
		Berlin	0	0	62	0	0	0
	Florence-Middlebury 115 kV line	Essex	0	23	69	0	0	0
		Highgate	0	29	90	0	0	0
		Berlin	0	27	83	0	0	0
	New Haven-Williston 115 kV line	Essex	0	0	49	0	0	0
		Highgate	0	0	57	0	0	0
		Berlin	0	0	75	0	0	0
	Williston-Tafts Corner 115 kV line	Essex	0	0	40	0	0	0
		Highgate	0	0	46	0	0	0
		Berlin	0	0	49	0	0	0

Reliability gap in MW with VY out of service	VY out of service	Locations	PV20@0 VT@1060	PV20@0 VT@1100	PV20@0 VT@1160	PV20@70 VT@1060	PV20@70 VT@1100	PV20@70 VT@1160
	West Rutland-Florence 115 kV line	Essex	0	0	40	0	0	0
		Highgate	0	0	51	0	0	0
		Berlin	0	0	48	0	0	0
	Florence-Middlebury 115 kV line	Essex	0	10	58	0	0	0
		Highgate	0	13	74	0	0	0
		Berlin	0	10	68	0	0	0
	New Haven-Williston 115 kV line	Essex	0	0	35	0	0	0
		Highgate	0	0	43	0	0	0
		Berlin	0	0	52	0	0	0
	Williston-Tafts Corner 115 kV line	Essex	0	0	29	0	0	0
		Highgate	0	0	35	0	0	0
		Berlin	0	0	34	0	0	0

Proposed affected & lead utilities		
	Lead utility:	GMP.
	Affected utilities:	All Vermont distribution utilities.
	Interregional:	New York utilities.

NTA screening	*Q 1: Is the proposed project's cost expected to exceed $2 million?* A 1: Yes *Q 2: Could elimination or deferral of all or part of the upgrade be accomplished through the use of non-transmission alternatives?* A 2: Yes *Q 3: Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $1,000,000?* A 3: Yes. Discussion: Although non-transmission alternatives are a viable means to address this group of deficiencies, obstacles may preclude their implementation. For energy efficiency to be a viable stand-alone NTA, the rate of load reduction must be large enough to eliminate the effects of long-term growth. Additional generation in the affected region, particularly near Essex, may be a viable NTA, particularly as part of a hybrid solution that includes some transmission reinforcements and/or additional power delivery commitments from New York. A detailed NTA analysis is underway.
Equivalency	The reliability deficiencies in Northwest Vermont occur as a result of an outage event when one transmission facility is already out of service. A non-transmission solution would not need to be in service under normal conditions, but would need to be on line at or above a Vermont load level of 1080 MW after a transmission facility is out of service. A non-transmission solution would need to be located north of the Tafts Corner substation to be effective.

System issues classified as "predominantly bulk"

The following 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. These projects involve a combination of grid elements owned by distribution utilities and elements owned by VELCO.

VELCO's identification of issues on the subsystem requires the assistance of local distribution utilities. 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 may 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 sub-system may not be identified as part of the Plan.

LOCATION	**COLCHESTER AREA**	
Analysis	Low voltages and overloads on the sub-transmission system	
When deficiency occurs	Line overloads when one element is out of service (N-1 conditions).	
Critical load level & timing of need	Critical load level Year of need	850 MW Past
Leading transmission solution	The upgrade of a 34.5 kV line from Lime Kiln to McNeil, and the installation of 34.5 kV capacitor banks. Estimated cost: $1M (provided by GMP).	
In service date	Summer 2015 (assuming typical design, public outreach, permitting and construction process timing).	
Status	Transmission and non-transmission alternatives will be evaluated by GMP.	
Proposed affected & lead utilities	**Lead utility:** GMP **Affected utilities:** GMP and BED	

NTA screening	*Q 1: Is the proposed project's cost expected to exceed $2,000,000?* A 1: No *Q 2: Could elimination or deferral of all or part of the upgrade be accomplished through the use of non-transmission alternatives?* A 2: No. Not applicable. Screened out in Q 1. *Q 3: Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $1,000,000?* A 3: Not applicable. Screened out in Q 1.
Equivalency	The reliability deficiencies in the Colchester region occur as a result of a single outage event. A non-transmission solution would need to be in service during all hours where the load level exceeds the critical load level. In this case, the non-transmission solution would need to be on line when the Vermont load is at or above 850 MW. A non-transmission solution would need to be located on the 34.5 kV system near McNeil.

LOCATION	**ST. ALBANS/EAST FAIRFAX AREA**	
Analysis	Low voltages and overloads. This is a predominantly bulk system deficiency that affects the sub-transmission system.	
When deficiency occurs	Loss of load will occur when one element is out of service (N-1 conditions.)	
Critical load level & timing of need	Critical load level Year of need	700 MW Past
Preferred transmission solution	The installation of a 115/34.5 kV transformer at the Georgia substation. Estimated cost: $5.1 Million (provided by CVPS, including ~$3 Million for 34.5 kV line reconductoring and $2.1 Million for 115/34.5 kV injection).	
In service date	Summer 2014 (assuming typical design, public outreach, permitting and construction process timing).	
Status	No additional analysis is planned for this reliability deficiency. Transmission alternatives were evaluated as part of the CVPS transmission study, and this solution was selected as the preferred transmission solution. CVPS also performed an NTA analysis, which indicated that non-transmission alternatives are not viable.	
Proposed affected & lead utilities	**Lead utility:** GMP **Affected utilities:** GMP and VEC	
NTA screening	A full NTA analysis was completed by CVPS.	

Equivalency	The reliability deficiencies in the St Albans/East Fairfax region occur as a result of a single outage event. A non-transmission solution would need to be in service during all hours where the load level exceeds the critical load level. In this case, the non-transmission solution would need to be on line when the Vermont load is at or above 700 MW. A non-transmission solution would need to be located on the 34.5 kV system near St Albans.

LOCATION	RUTLAND AREA (BLISSVILLE, NORTH RUTLAND, COLD RIVER)	
Analysis	Low voltages and overloads.	
When deficiency occurs	Overloads will occur when one element is out of service (N-1 conditions.) This is a predominantly bulk system deficiency that affects the sub-transmission system.	
Critical load level & timing of need	Critical load level Year of need	1000 MW Past
Leading transmission solution	The installation of a 115/46 kV transformer at the West Rutland substation, 46 kV capacitor banks, and the rebuild of 46 kV lines at an estimated cost of at least $35M, based on the current scope.	
In service date	Summer 2015 (assuming typical design, public outreach, permitting and construction process timing) subject to additional analysis by GMP.	
Status	Transmission and non-transmission alternatives are being evaluated by GMP.	
Proposed affected & lead utilities	**Lead utility:** GMP **Affected utilities:** GMP	
NTA screening	*Q 1: Is the proposed project's cost expected to exceed $2,000,000?* A 1: Yes *Q 2: Could elimination or deferral of all or part of the upgrade be accomplished through the use of non-transmission alternatives?* A 2: Yes. *Q 3: Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $1,000,000?* A 3: Yes. A non-transmission alternative may be a hybrid solution that includes capacitor bank installations on the 46 kV system to address low voltages, particularly as a result of the Blissville transformer outage.	
Equivalency	The reliability deficiencies in the Rutland area region occur as a result of a single outage event. A non-transmission solution would need to be on line at or above a Vermont load level of 1000 MW and be located on the 46 kV system near the North Rutland and Cold River substations.	

Location	Hartford area (Hartford, Chelsea)	
Analysis	Low voltages in the Hartford subarea.	
When deficiency occurs	Low voltages will occur when one element is out of service (N-1 conditions.) This is a predominantly bulk deficiency that affects the sub-transmission system.	
Critical load level & timing of need	Critical load level Year of need	1000 MW Past
Leading transmission solution	The installation of a 115/46 kV transformer at the Hartford substation. Estimated cost: $20M.	
In service date	Summer 2015 (assuming typical design, public outreach, permitting and construction process timing)	
Status	Transmission and non-transmission alternatives are being evaluated by GMP.	
Proposed affected & lead utilities	**Lead utility:** GMP **Affected Utilities:** GMP	
NTA screening	*Q 1: Is the proposed project's cost expected to exceed $2,000,000?* A 1: Yes *Q 2: Could elimination or deferral of all or part of the upgrade be accomplished through the use of non-transmission alternatives?* A 2: Yes *Q 3: Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $1,000,000?* A 3: Yes	
Equivalency	The reliability deficiencies in the Hartford region occur as a result of a single outage event. The non-transmission solution would need to be on line at or above a Vermont load level of 1000 MW and located on the 46 kV system between the Hartford and Bradford substations, and between Silverlake and Hartford.	

Location	Northern area (Highgate, Jay, Newport, Irasburg, Burton Hill)
Analysis	Low voltages in the northern subarea.
When deficiency occurs	Low voltages will occur when one element is out of service (N-1 conditions.) This is a predominantly bulk deficiency that affects the sub-transmission system.
Critical load level & timing of need	Critical load level: 1000 MW Year of need Burton Hill 46 kV capacitor banks: Past Newport Station upgrade: 2014 Irasburg transformer upgrade: 2016 Moshers Tap upgrade: 2022
Preferred transmission solution	The upgrade of the Newport 115/46 kV station to supply the load when the Stanstead line is out of service. Addition of 46 kV capacitor banks. Upgrade of the Irasburg transformer and the Moshers Tap to supply additional loads. These upgrades will be completed in stages as the load continues to grow. **Estimated costs:** Burton Hill 46 kV capacitor banks $3M Newport Station upgrade $7M Irasburg transformer upgrade $6M Moshers Tap upgrade $3M
In service date	Completed in stages, starting as early as 2013.
Status	Studies of transmission and non-transmission alternatives have been completed. However, analyses continue to be performed to take into account any changes in load predictions and other factors.
Proposed affected & lead utilities	**Lead utility:** VEC **Affected utilities:** VEC, Swanton, Enosburg, Barton, and Orleans
NTA screening	A full NTA analysis was completed by VEC and VELCO.
Equivalency	The reliability deficiencies in the Northern region occur as a result of a single outage event. The non-transmission solution would need to be on line at or above a Vermont load level of 1000 MW and located on the 46 kV system between the Jay and Irasburg substations.

LOCATION	IBM AREA	
Analysis	Loss of load	
When deficiency occurs	Due to the multiple taps on the 115 kV lines supplying IBM, loss of load can happen and has happened when a fault occurs on these lines. This is a predominantly bulk deficiency.	
Critical load level & timing of need	Critical load level Year of need	<700 MW Past
Leading transmission solution	Reconfiguration of the taps into substations. Estimated cost: Unknown	
In service date	Unknown	
Status	Transmission analysis to be completed by June 2013.	
Proposed affected & lead utilities	**Lead utility:** GMP **Affected utilities:** GMP	
NTA screening	*Q 1: Is the proposed project's cost expected to exceed $2,000,000?* A 1: Yes *Q 2: Could elimination or deferral of all or part of the upgrade be accomplished through the use of non-transmission alternatives?* A 2: No. Non-transmission alternatives cannot resolve the configuration concerns. *Q 3: Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $1,000,000?* A 3: Not applicable. Screened out in Q 2.	
Equivalency	The reliability deficiencies near IBM occur as a result of a single outage event. The non-transmission solution would need to be on line at all hours and located on the 13.8 kV system at IBM.	

LOCATION	VERNON ROAD 115 KV STATION	
Analysis	Loss of load in the Brattleboro subarea.	
When deficiency occurs	Load in the Brattleboro area is at risk of outages during maintenance activities or under outage conditions when one element is out of service (N-1 conditions.) This is a predominantly bulk deficiency that affects the sub-transmission system.	
Critical load level & timing of need	Critical load level Year of need	<700 MW Past
Preferred transmission solution	The installation of a 115 kV breaker at the Vernon Road substation Estimated cost: $1.9 Million. (Provided by CVPS.)	
In service date	Summer 2013 (assuming typical design, public outreach, permitting and construction process timing).	
Status	Transmission and non-transmission alternatives are being evaluated by GMP.	
Proposed affected & lead utilities	**Lead utility:** GMP **Affected utilities:** GMP **Regional:** NGRID, Northeast Utilities	
NTA screening	*Q 1: Is the proposed project's cost expected to exceed $2,000,000?* A 1: No *Q 2: Could elimination or deferral of all or part of the upgrade be accomplished through the use of non-transmission alternatives?* A 2: No. Not applicable. Screened out in Q 1. *Q 3: Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $1,000,000?* A 3: Not applicable. Screened out in Q 1.	
Equivalency	The reliability deficiencies in the Brattleboro region occur as a result of a single outage event. The non-transmission solution would need to be on line at all hours and located on the 69 kV system near Brattleboro.	

Subsystem results

The following section describes reliability issues classified as "subsystem" meaning they do not meet the definition of bulk transmission system, but are above distribution system voltage levels. These projects involve grid elements owned by distribution utilities.

The 2012 analysis identified several potential sub-transmission reliability issues. The following table shows which system element causes the potential reliability issue. The problems are categorized as to whether each causes high or low voltage, or as a thermal issue in which equipment exceeds its rated temperature. These findings are based on VELCO's statewide analysis. System analysis by the affected utilities using different reliability criteria may produce different results.

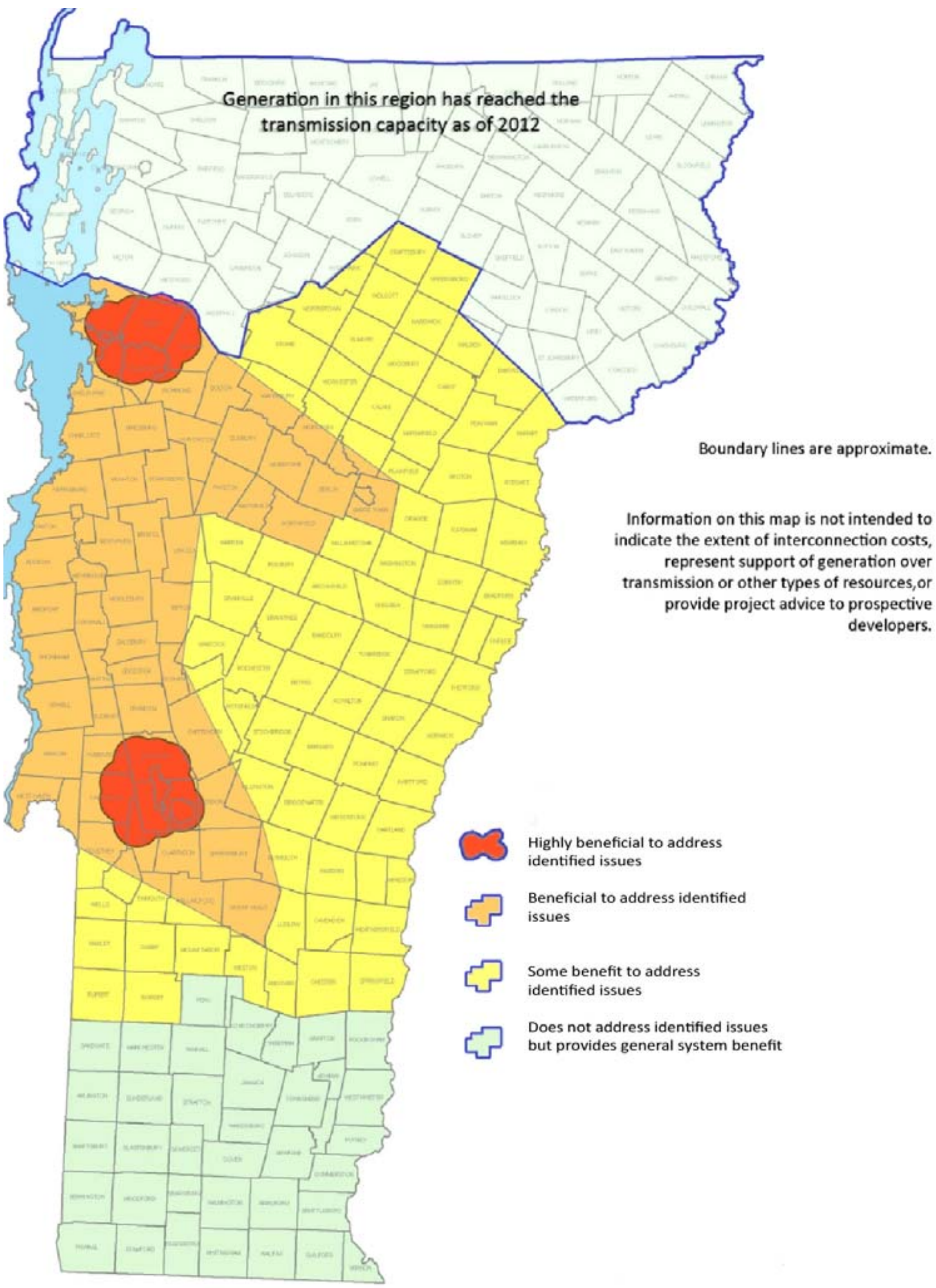
The table identifies sub-transmission areas with potential reliability issues. Flexibility is permitted at the subsystem level concerning the reliability criteria the system must meet because the sub-transmission system is not currently subject to mandatory federal reliability standards. For example, it may be acceptable in the area to incur an infrequent power outage rather than to invest in infrastructure to eliminate the power outage risk. 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 (Projects needed in past listed as 2012 in this table)	90/10 Load Forecast for Year (MW)	Contingency	Reliability Concern	N-1 Criteria Violation	Affected DUs	Lead DU
Hartford	2022	1130	None	Low Voltage	Newbury	GMP	GMP
Hartford	2012	970	Transmission / Transformer	Low Voltage	Hartford area	GMP	GMP
Hartford	2014	1090	Transformer	Thermal	Taftsville - Quechee Tap	GMP	GMP
Hartford	2022	1130	Transformer	Thermal	Quechee Tap - Norwich Tap	GMP	GMP
Chelsea / Hartford	2012	<1065	Transmission / Transformer	Voltage collapse	Chelsea and Hartford areas	GMP	GMP
Chelsea	2022	1130	Transmission / Transformer	Delta Voltage	Chelsea area	GMP	GMP
Ascutney	2017	1100	Subtransmission	Low Voltage	Charlestown	GMP / PSNH	GMP
Ascutney	2017	1100	Subtransmission	Low Voltage	Joy / Maple Ave	GMP / PSNH	GMP
Ascutney	2017	1100	Subtransmission	Thermal	North Springfield Tap - Riverside Tap	GMP / PSNH	GMP
Ascutney	2012	<1065	Subtransmission	Thermal	Ascutney - Highbridge - Lafayette	GMP / PSNH	GMP
Ascutney	2015	1095	Subtransmission	Thermal	Lafayette - Joy	GMP / PSNH	GMP
Ascutney	2021	1125	Subtransmission	Thermal	Lafayette - Claremont Paper	GMP / PSNH	GMP
Ascutney	2012	<1065	Subtransmission	Voltage collapse	Charlestown / Lafayette	GMP / PSNH	GMP
Blissville	2012	1020	Transformer	Low Voltage	Blissville area	GMP	GMP
Blissville	2012	<1065	Transformer	Thermal	Castleton - West Rutland	GMP	GMP
Blissville	2012	<1065	Transformer	Thermal	Hydeville - Blissville	GMP	GMP
Rutland	2012	1060	Transformer	Thermal	Cold River	GMP	GMP
Rutland	2012	1030	Transformer	Thermal	North Rutland	GMP	GMP
Rutland	2012	<1065	Transformer	Thermal	West Rutland - Proctor - Florence	GMP	GMP
Stowe	2022	1130	Transmission / Subtransmission	Low Voltage	Stowe	WEC, Stowe, Morrisville, Hardwick	Stowe
Montpelier	2022	1130	Subtransmission	Low Voltage	Barre / North End	GMP	GMP
Montpelier	2012	<1065	Subtransmission	Thermal	Berlin - Mountain View Tap - Mountainview	GMP / WEC	GMP
Montpelier	2012	<1065	Subtransmission	Voltage collapse	South End / Websterville / Legare	GMP	GMP
Montpelier	2020	1120	Transmission	Thermal	Barre	GMP	GMP
St. Albans	2012	700	Transmission / Subtransmission / Transformer	Thermal / Voltage collapse	St. Albans / Fairfax area	GMP / VEC	GMP
St. Albans	2012	820	Transformer	Thermal	St. Albans	GMP / VEC	GMP
St. Albans	2012	<1065	Subtransmission	Thermal	Fairfax Falls - VEC11 - Husky Tap	GMP / VEC	GMP
St. Albans	2022	1130	Transmission / Transformer	Low Voltage	Underhill	GMP / VEC	GMP
Burlington	2012	840	Subtransmission / Transformer	Thermal	Gorge - McNeil 46Y1 Tap	GMP / BED	GMP
Burlington	2022	1130	Subtransmission / Transformer	Thermal	McNeil 46Y1 Tap - McNeil	GMP / BED	GMP

Relative benefits of non-transmission alternatives based on location

A number of the reliability concerns identified in this plan may be addressed, in whole or in part, by new generation or significant new demand-side programs that reduce peak load, based on VELCO's analysis and the results of ISO-NE's assessment of non-transmission alternatives completed in conjunction with the VT/NH Needs Assessment. The following discussion focuses on generation, but the locational benefits are also applicable to load reduction through energy efficiency or demand response.



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As discussed in the section on equivalency (page 17), the effectiveness of generation as an NTA depends on its location. For example, a 50 MW generator installed in one location may provide the same reliability benefit as a generator twice its size, if the 50 MW generator is more optimally located. New generation can also aggravate a reliability concern if installed at the wrong location. The map below shows where generation can be more or less effective at improving system reliability and, thus, potentially deferring one or more transmission solutions.

Generation located near Burlington should have a positive effect for most of the state. Similarly, generation located near Rutland should have a positive effect for the Central Vermont area. Generation that is located in the general vicinity of these towns and alongside the transmission corridors in Chittenden, Washington, Addison and Rutland counties provide similar benefits, but at a reduced effectiveness.

The northern portion of the state, where the wind generation potential is relatively high, lacks sufficient transmission to accommodate additional utility-scale generation and the addition of new, utility-scale projects will likely require transmission reinforcements. Even in this part of the system, generation located on the distribution and sub-transmission systems may provide reliability benefits. Similar benefits can be achieved in the southern part of the state as well.

Additional generation, as well as load reduction, can have both positive and negative effects on the system, depending upon the technology utilized and other factors, such as location and size. The more negative the effects, the more likely transmission reinforcements will be required. Some of the negative effects may include:

- Increased transmission losses.
- The need for additional transmission reinforcement to interconnect.
- Increased operating costs when additional generation is needed to backup intermittent supply.
- Hindered grid maintenance where interconnections are inadequate to permit maintenance to be done at an optimum time.

Generation and load reduction may also offer positive benefits to the system including:

- Reduced losses.
- Decreased reliance on out-of-state generation.
- Avoided costs of transmission reinforcements.
- The potential to facilitate grid maintenance.
- Smoother load restoration after an outage.
- Other services to the state and New England as a whole, such as reserves, capacity, reactive support, energy, and other contributions.

Public Input on the 2012 Plan Update

VELCO conducted an extensive public engagement process to meet the requirements of 30 V.S.A. 218c and to actively solicit public input on 2012 Vermont Long-Range Transmission Plan—Public Review Draft. Opportunities for input included public meetings hosted by VELCO, presentations at regional planning commissions, an online comment form, and an invitation for comments by mail or phone.

In April, VELCO announced four public forums on the draft Plan, in West Dover April 26, Rutland May 1, Burlington May 8 and Montpelier May 10, and promoted them with an email invitation followed by a postcard mailing sent to over 2,000 contacts. VELCO also advertised the public forums with a total of 46 display ads in the *Addison Independent, Bennington Banner, Brattleboro Reformer, Burlington Free Press, Manchester Journal, Newport Daily Express, St. Albans Messenger, Stowe Reporter, Rutland Herald*, and *Times Argus* and sent press releases to these and other media outlets.

In addition to the four public forums, VELCO offered to attend and make a presentation of the draft plan to each of the 12 regional planning commissions. Seven presentations were scheduled from May 15 through July 26 including: Windham, Rutland, Southern Windsor, Lamoille, Two-Rivers, Central Vermont and Addison County.

As required by law, VELCO created a verbatim record of public questions and comments from the public forums. The transcribed comments are available at http://www.velco.com/LongRange .

Total attendance at the public forums was 45. While the quality of discussion was very high at all sessions, we remain disappointed at not drawing a larger audience, though experience has shown that it is difficult to engage the public on transmission planning issues unless and until a specific project has the potential to affect stakeholders' communities. We will continue to seek more effective means of engaging the public earlier.

The following section summarizes and responds to the themes that emerged from the public comment process and how they have been addressed in the final 2012 Vermont Long-Range Transmission Plan.

NOTE: A number of questions raised in public meetings on the plan concerned issues beyond transmission planning, such as power supply. The **Vermont Comprehensive Energy Plan** provides detailed information on many of these topics. The following section refers readers to specific pages in Volume 2 of the CEP for more information where appropriate. The CEP can be downloaded from http://www.vtenergyplan.vermont.gov/

THEME 1—Distributed generation: Many participants advocated greater reliance on serving Vermont load through local, small-scale and renewable generation. The questions and comments included:

- How is small-scale, local generation taken into consideration in the Plan?
- How do planners take net metering and SPEED resources into account?
- What percentage of Vermont power supply is coming from net metering and SPEED?
- How and why do you differentiate net metering and SPEED?
- Does Vermont have a "feed-in-tariff"?
- The more local power and distributed generation the better. In the long run, it will be less expensive and more manageable to have more local power.
- How much solar energy is available and is it useful for reliability?
- How do you determine how much output you count from renewable resources, like wind and hydro?
- Why do Vermont utilities sell the renewable energy certificates (RECs) from their renewable power supply?

RESPONSE: At the time of this writing, Vermont utilities are conducting a full-scale non-transmission alternatives (NTA) analysis to identify potential alternatives to the Northwest and Central Vermont reliability issues described on pages 24-29. The study screened 22 different types of resources, including small-scale, renewable and distributed generation. Solar power is among the resources being studied, and is seen to offer significant potential for serving Vermont's electric demand at peak times, which typically occur on hot, sunny summer days. Information about the study is available on the VSPC website (**www.vermontspc.com**).

As discussed on page 16, small-scale renewable resources are generally accounted for in this Plan as reductions in projected load because they are typically connected to the distribution system. Utilities are now seeing significant increases in the amount of these resources projected to connect to the electricity grid in the next several years, and are collaborating within the VSPC and other forums to more accurately predict future impacts. VELCO anticipates needing to more precisely incorporate small-scale distributed resources into future updates of the Vermont load forecast and will continue to work with the distribution utilities, VEIC, DPS and other Vermont entities to accomplish this task. The cumulative effect of many projected small-scale projects stimulated by recent policy changes and reductions in the cost of technology may well make a meaningful contribution toward meeting Vermont's peak electricity demand within the next planning cycle.

For a discussion of how planners determine how much output to count from hydroelectric and wind power, see page 7.

More information about small-scale, renewable generation is available in Vol. 2, **CEP**, page 130 for net metering, 135 for SPEED and Renewable Energy Certificates, 137 for the feed-in tariff or standard offer, and 65 for Vermont electric energy supply.

THEME 2—Energy efficiency: Some participants emphasized the importance of energy efficiency as a means of avoiding the need for new transmissions upgrades.

Response: Energy efficiency plays a very important role in Vermont's electric system as a result of long-standing public policy and investment. Reliability needs in this Plan are based on demand forecasts that incorporate historical energy efficiency and future efficiency projected by VEIC. For more information about how energy efficiency is incorporated into the Plan, see page 12.

THEME 3—Transmission funding: Many questions arose in public forums about how Vermont transmission upgrades and alternatives to transmission are funded. Among the questions and comments:

- What is Vermont's share of the funding if these transmission projects need to be built? The Plan should show not just total cost, but also Vermont's share under the regional cost-sharing formula.
- Are the costs in the plan total costs of construction or what you pay?
- Who owns the assets you have to build for reliability reasons? Does it disadvantage VELCO to have an NTA solve the problem because that will not be your asset?
- How would a generation solution affect Vermont ratepayers differently from a transmission solution? Why wouldn't capacity payments support the generator and make it economically viable?
- Because of FERC and ISO-NE requirements, we have to pay even if we are successful in shifting to distributed, local power.
- Can Vermont opt to pay for a solution to a problem in New York if it solves a Vermont problem in a less costly manner than a Vermont-based solution?

Response: Questions about funding raised in public forums identified the need for a discussion of transmission project funding, which has been added in this final version of the plan. (See page 10.) In addition, project costs in the Transmission Results section, beginning on page 19, have been supplemented to include both total cost of construction and the estimated Vermont ratepayer share of the transmission solution, assuming all costs are classified as “Pool Transmission Facilities (PTF)” and thus allocated across New England.

When VELCO builds a transmission project, it owns the resulting assets. If a problem can be solved by a non-transmission alternative, the alternative would be owned by the developer, which could be a Vermont distribution utility or a third-party. Before VELCO can seek a permit for a transmission solution, we are required to analyze whether it is possible to address reliability concerns with non-transmission alternatives, such as generation or demand reduction, to the extent these non-transmission alternatives are cost-effective and feasible. VELCO is not disadvantaged by choosing an NTA to address a system need as long as the solution satisfies the need based on adequate evaluation. The evaluation of alternatives takes place through the collaborative VSPC process, well before permitting begins. Although challenges exist to funding non-transmission alternatives, the process ensures non-transmission options get full and timely consideration, as in the case of the full-scale NTA study now underway by Vermont utilities on issues identified in this Plan.

In the case of the Plattsburgh-Sand Bar issue discussed on page 8, public participants asked whether Vermont could pay for upgrades in New York that would enable Vermont to count on power flows across this interstate tie, and if such upgrades would be a less expensive reliability solution than new transmission in Vermont. At this writing, it appears New York is planning to undertake the necessary upgrades. This action along will not restore Vermont’s ability to count on power flows over the Plattsburgh-Sand Bar tie without further actions to secure a contractual power source that ISO-NE agrees will provide adequate assurance that Vermont can count on those power flows. The issue remains in flux and subject to continuing development and negotiation as of this writing.

THEME 4—Impacts of project construction. Participants in the public forums on the plan asked for more information about likely impacts of construction in those areas where a transmission solution needs to be built. They asked:

- Will VELCO need to acquire new rights-of-way?
- Will existing corridors need to be widened?
- What do you mean when a project involves a “rebuild” of an existing line?

Response: VELCO’s policy is to use existing rights-of-way wherever possible. The projects identified in this Plan would all involve construction in existing utility rights-of-way. In one case—the Connecticut River Valley reliability issues described on pages 22-23—two potential routes were shown, including the existing VELCO corridor and the most likely alternative route (shown on the map in green) along an existing GMP (formerly CVPS) subtransmission right-of-way.

In some cases, it may be necessary to widen the cleared area within an existing easement in order to accommodate an upgraded line or a new line within the same corridor. In limited instances, new easements may be needed.

The phrase “rebuild” implies increasing the capacity of the existing line, which typically involves replacing the wires with larger wire and replacing some or all of the structures to accommodate the new wire or due to the condition of the existing structures.

THEME 5—Location of non-transmission alternatives. Participants asked questions about where non-transmission alternatives could be sited to provide reliability benefits and potentially avoid the need for transmission system upgrades. Questions included:

- What determines the areas that are most beneficial for locating NTAs?
- Does Vermont have incentives to locate generation in the places that will benefit system reliability?

Response: The map on page 39 depicts the relative benefit of generation or load reduction in addressing reliability gaps identified in the Plan. It shows that resources located in the load pockets of Rutland and Burlington would have the greatest benefit to system reliability. The relative benefits shown on the map are based on VELCO analysis, and are illustrated in the tables discussing the Central and Northwest VT regional reliability groupings on pages 24-29.

Vermont currently funds some geographical targeting of energy efficiency programs that is designed to promote greater energy efficiency in places where load reduction may avoid or defer the need for grid improvements. None of the areas that are currently geographically targeted is sufficient to address the specific bulk electric system issues identified in the Plan.

Act 170 of the 2012 Vermont General Assembly, the 2012 Energy Act, creates what may function as a new incentive for small, renewable energy projects (2.2 MW capacity or less) to locate in areas that will provide a reliability benefit to the grid. The Act raises the cap on cumulative capacity for “feed-in tariff” or “standard offer” projects from 50 MW to 127.5 MW over several years. It exempts from the cap “new standard offer plants that the [Public Service] board determines will have sufficient benefits to the operation and management of the electric grid…” and requires utilities to identify constrained areas. The goal of these provisions is to encourage developers to locate in the constrained areas, as well as provide the information needed to make siting decisions that help meet reliability needs.

THEME 6—Maps. Participants requested the addition of maps to the Plan showing the transmission system as a whole and the ISO-NE region.

Response: These two maps have been added to the Plan.

THEME 7—Naming of regions. Various participants found the naming of the regional groupings of bulk system deficiencies to be confusing. They pointed out that the labels “Central Vermont” and “Northwest Vermont” do not appear to conform to common understandings of Vermont geography.

Response: The geographical confusion arises because the labels in the Plan refer to the areas of load that have the largest impact on the identified transmission need, not the areas where upgrades would have to be constructed in order to resolve the need. For example, load in Chittenden County is the largest driver of the Northwest Vermont deficiencies, but the transmission solution would likely be constructed between West Rutland and Tafts Corners. Although we recognize the confusion, the labels in the Plan have now been used for many months in the current NTA study, and in various study reports and documentation at ISO-NE. At this point, we believe that changing the terms would create even more confusion, and so have retained the labels that were in the public review draft. If and when transmission projects to address these deficiencies reach the stage of project-specific public outreach, we will consider renaming the projects.

THEME 8—Need dates: Participants asked whether VELCO is in danger of being penalized for the reliability deficiencies identified in the Plan that were needed at load levels Vermont has already reached, i.e., whose need dates are in the past.

Response: The reliability issues that arise at load levels already reached are the most urgent to be addressed. VELCO is moving forward with the Connecticut River Valley issue for this reason. The ability to document affirmative plans to address this deficiency should be sufficient to avoid any potential for penalties during the planning, permitting and construction of this project. The other project for which one segment has need dates that are in the past is the Central Vermont deficiency. This project is currently the subject of a full-scale non-transmission alternatives study by Vermont utilities that may identify a cost-effective non-transmission alternative. The utilities expect to complete this analysis by the end of the year and will then proceed with planning and permitting of the most cost-effective solutions.

THEME 9—Non-transmission alternatives. Participants had a number of questions regarding non-transmission alternatives:

- What is a non-transmission alternative?
- Explain "screened in" versus "screened out."
- What is the alternative for the two areas identified as having NTA potential?
- Is there a real-world example of an NTA?
- Who should people talk to if they are interested in the NTA analysis that is underway?

Response: Non-transmission alternative, or NTA, is generation and/or reduced demand in a configuration that can address a need that would otherwise be met with a regulated transmission solution. Demand reductions can come from energy efficiency or "demand response" programs in which customers are paid for shutting off power-using equipment or turning on power-producing equipment or systems when called on by grid operators. Hybrid solutions are NTA configurations that include some, but not all, of the otherwise-needed transmission solutions at a lower cost than the transmission solution alone.

"Screened in" versus "screened out" refers to a set of three questions used to determine whether sufficient potential for a deficiency to be resolved with NTAs exists to warrant the large investment of resources needed to do a full NTA study, which can cost in the hundreds of thousands of dollars. If the potential exists, the reliability concern is characterized as "screened in." The current NTA screening tool is available on the VSPC website at this location: http://bit.ly/LYIYfE . At the time of publication, the tool was undergoing revision to reflect recent changes to the process proposed by the VSPC and approved by the PSB in Docket 7081.

VELCO conducted full-scale NTA studies as part of the Northwest Reliability Project in 2005 and the Southern Loop project in 2007. Individual utilities and the Energy Efficiency Utility have implemented NTAs to defer or avoid line upgrades in the past, such as geographically targeted energy efficiency and a CVPS project to defer a portion of the Southern Loop upgrade. An NTA study now underway to identify non-transmission alternatives to the Northwest and Central Vermont reliability issues documented in this Plan is the first full-scale NTA study since the inception of the VSPC process in 2007. This study involves the full collaboration of distribution utilities, led by GMP, and active participation of other VSPC members, such as the Vermont Energy Investment Corporation. For more information about NTA studies, visit the VSPC website at www.vermontspc.com .

THEME 10—Peak demand versus energy usage. Various participants pointed out the need for a better understanding among all energy stakeholders and policy makers about the difference between peak demand and usage. The difference between the two concepts is not always well-understood.

Response: As discussed on page 11 of the Plan, transmission planning is concerned with the ability of the transmission system to meet projected customer's highest power demand, measured in kilowatts or megawatts.

Power supply is concerned with the ability of the electric system to meet projected customer energy use over time, measured in kilowatt-hours or megawatt-hours. In essence, transmission planning is focused on ensuring the pipe is big enough to carry power flows under various system conditions, including at the time of highest or peak demand, which in New England is a hot summer day. Understanding of the concept of peak demand, as differentiated from energy usage, will become especially valuable as consumers gain more tools and information through smart meters and demand response to reduce peak demand and thereby potentially avoid the need for demand-driven upgrades.

Theme 11—The planning process. Participants had many questions and comments regarding the planning process including:

- What was the date of the initial plan that this plan is updating?
- How do you decide on the lead utility?
- What is economic transmission?

Response: VELCO has prepared several long range plans at various times in its history. Pursuant to 30 V.S.A. § 218c, VELCO published a 10-year plan in 2006. Prior to that state requirement, VELCO had prepared a long-range plan in 2001. Pursuant to PSB Docket 7081, VELCO published a 20-year plan in 2009, which is being updated by this 2012 plan.

The lead utility is proposed by VELCO as part of developing the Plan, and must be agreed to by the utilities affected by a given reliability deficiency. If the utilities cannot agree, the VSPC process includes a mechanism for selecting the lead utility. The lead utility is defined in Docket 7081 as the utility "selected by agreement of the affected utility…to serve the functions of coordination, assuring performance of NTA analysis and facilitating necessary decision-making, and primary contact point for the reliability deficiency…" in question. While there are no specific selection criteria, factors may include the impact of the problem, the likely role in a solution, and the capability to lead the analysis.

Economic transmission refers to transmission projects undertaken on a commercial basis rather than to solve an identified reliability deficiency. An example would be to increase the capacity of a transmission corridor that otherwise limits the ability to transfer power from one part of the system to another. A discussion of economic transmission is included on page 13 of the Plan.

THEME 12—Public outreach on transmission planning. Participants had feedback and questions regarding public outreach on transmission planning including:

- Communication with the public is valuable despite the challenges of getting the public's attention before a specific project is proposed in their backyard. Continue to explain to the public what you are doing.
- How much communication occurs among those who are trying to serve the load and those who are considering developing transmission or generation? From the standpoint of matching generation up with transmission needs, the system would benefit from an overt, iterative process that was easily accessible to interested stakeholders.
- Why did you not hold a meeting in the Northeast Kingdom?
- Please develop a handout that addresses the pros and cons of different pole heights, and another on EMFs. It would be helpful to energy committees to be able to explain these issues.

- When you are doing public outreach on a potential transmission project, do not rely solely on the select board to represent the town. You need to get information out through other channels for the general public to be aware of what is coming.

Response: We strongly agree with the value of public information about transmission and other electric system issues. VELCO conducts public outreach at every stage of addressing system needs from the long-range plan development to planning specific projects to the permitting process. We will consider developing generic handouts on the suggested topics in connection with our next transmission project. We are currently working to improve the user-friendliness and accessibility of system information to potential developers through our website and other communication tools, and are supporting the efforts of the VSPC to increase involvement of generation developers in the planning conversation.

Because of public interest in the issue of wind development, some participants felt VELCO should have held a public outreach meeting on the Plan in the Northeast Kingdom. The Vermont statute that requires us to update our 20-year long-range transmission plan every three years also requires at least two public information meetings when the Plan is in draft form. VELCO hosted four workshops in West Dover, Rutland, Burlington and Montpelier respectively. In addition, we offered presentations to all Vermont Regional Planning Commissions, including the Northeast Vermont Development Association, and, pursuant to that offer, made presentations at seven regional planning commissions and a special meeting in Newark by invitation of its local planning commission. Because no bulk system upgrades are proposed for the Northeast Kingdom, and NTAs located there will have little or no impact on the reliability deficiencies identified in the Plan, we concluded that a special workshop on the plan in the Northeast Kingdom was unnecessary. We remain willing to visit with any group that invites us to make a presentation on the Plan.

When VELCO conducts public outreach, we work with many and varied groups, having previously learned to not limit communication only to the town select boards. As local energy committees have developed in many communities and energy has become an increasing focus of regional and local planning commissions, we are turning in particular to those groups to help us understand the energy landscape of local areas.

THEME 13—Regional issues. Because of the importance of ISO-NE, NPCC and NERC in the planning process, a number of questions arose regarding these regional and national organizations. Participants asked:

- Who manages the power exchange, the market, what power sources get tapped and when?
- What is ISO-NE's role in the planning process?
- Who funds ISO-NE, NPCC and NERC?

Response: ISO-NE operates the wholesale power markets in the New England region and is responsible for operating the transmission system. Their responsibilities include dispatching power generators to serve anticipated load and ensuring reliability of the transmission system both through real-time operation and long-term planning. For more information about their operations, funding and market operations, see www.iso-ne.com . ISO-NE's role in the Vermont planning process is discussed on page 9 of the Plan.

ISO-NE and NERC are funded by wholesale customers and entities through their payments for transmission service. NPCC is funded primarily by NERC.

THEME 14—GMP-CVPS merger-related questions. Some participants were concerned about potential impacts on Vermont's transmission system of the proposed merger between GMP and CVPS. Their concerns included:

- Concern that transmission will be built across Vermont to bring power to other areas but that the lines will benefit Vermont.
- Concern that the merger could result in Vermont becoming the corridor to bring Canadian power to southern New England. In particular, that Vermont could be a substitute corridor for the proposed Northern Pass Project in New Hampshire.

Response: Any transmission project in Vermont continues to require regulatory approval from the Vermont Public Service Board. In order to be approved, a proposed project must meet the Vermont statutory criteria for a Certificate of Public Good (see Vermont Statutes, Title 30, Section 248), which include a showing that the project "will result in an economic benefit to the state and its residents" along with many other criteria. The merger does not change the threshold tests that a project must meet for Vermont regulatory approval.

THEME 15—The impact of geomagnetic solar storms on the grid. Some participants expressed strong concern about the preparedness of the grid to weather the solar storms that are expected during the curren period of high solar activity. Questions included:

- People need more information about what you are doing to prepare for the solar maximum.
- Whose role is it to address the solar storms issue: you or ISO-NE?

Response: At every level of the electric system, reliability organizations and grid operators have prepared to protect the grid from damage caused by geomagnetic storms. VELCO has procedures in place governing our operation of Vermont's system in compliance with ISO-NE, NPCC, and NERC requirements. VELCO is also considering installation of additional monitoring equipment on critical transmission facilities to enable continuous monitoring of the impacts of geomagnetic storms and to facilitate appropriate actions. The following links provide more detailed information on system preparedness and procedures:

- ISO-NE Solar Magnetic Disturbance Remedial Action: http://bit.ly/M5Kkm7
- ISO-NE Newswire article on ISO solar storm procedure: http://bit.ly/KuVWlV
- NPCC Procedures for Solar Magnetic Disturbances: http://bit.ly/MHSTlG

THEME 16—Technology and system security. Participants raised several questions concerning investments in technology and enhancements to system security. Questions included:

- Why doesn't the Plan discuss investments in new technology for greater reliability in control systems, control center operations and emergency procedures?
- Are you considering hardening your systems for greater security, and how does this fit into your planning?
- Does VELCO's system employ the latest smart grid technology?
- What percentage of power is lost to transmission line losses?

Response: The elements of the Plan are dictated by Vermont law and regulation and are focused on identifying reliability deficiencies that may require new or upgraded lines and other transmission facilities. Many other standards and requirements, on which VELCO is regularly audited, govern system operations and security, and are not addressed in this Plan.

VELCO's system incorporates many advanced technologies such as FACTS (flexible alternating current transmission system) devices, sensors, and HVDC (High Voltage Direct Current.) As such, the system is fairly state-of-the art, but implementation of new technologies on vital systems only occurs once the technology is proven to be reliable and cost-effective.

A rough estimate of line losses in transmission is 1 to 2 percent.

THEME 17—Ties & transfers. Participants sought clarification concerning power flows in and out of Vermont including:

- What is the difference between transfers and tie lines?
- Why is there no discussion regarding ties and transfers north to south? Why so much emphasis on the east to west and west to east flows when so much of our power comes from the north?
- How many lines connect Vermont to the New England region? Other regions?
- Are the issues concerning transfers related to wheeling? Are these needs about getting power to market? Could this be like Enron in California?

Response: Tie lines are transmission lines that connect, or tie, one region to another. Vermont is connected to Canada via two lines, to New York via three lines, to Massachusetts via three lines, and to New Hampshire via eight lines.

Vermont only imports about 30% of its power from Canada in the north, and the connections to the north can only deliver a set amount. The transfer variations in the north-south direction, therefore, are small. Alternatively, Vermont is affected by flows from or to New York at its western border and flows from or to New Hampshire at its eastern border. These flows are several times larger than north-south flows through Vermont.

The transfer issues in the Plan are unrelated to economic transmission and are concerned solely with system reliability. Vermont is part of an interconnected system, and therefore is affected by flows between regions within and outside of New England.

THEME 18—Planning for emerging trends. Participants recognized that significant changes are underway in the energy environment and asked how these trends were taken into consideration in the development of the plan:

- How do you plan for uncertain future trends such as electric vehicles and smart meters?
- Peak demand pricing can and will have a significant effect on planning.

Response: The plan includes a section on "Inherent uncertainties in the timing of need for reliability solutions" that describes how smart grid, electric vehicles and future changes in rate design (e.g., peak demand pricing) influenced the plan. While planners expect these changes to affect demand within a few years, their effects are as yet uncertain; some trends, such as electric vehicles, could either decrease or increase load. VELCO will continue to work with the distribution utilities, VEIC, DPS, and other Vermont entities to improve how these factors are accounted for in load forecasts. The three-year cycle for updating the Plan provides the opportunity to adjust load forecasts regularly and adapt as the effects of emerging trends become more quantifiable.

THEME 19—Vermont Yankee. Many participants sought clarification about how Vermont Yankee was treated in developing the Plan.

Response: The studies that are the basis for the Plan evaluated system reliability both with and without Vermont Yankee. The treatment of VY and the conclusions of the analysis are summarized beginning on page 14. Results are given both with and without VY in the report of bulk system issues that begins on page 19.

THEME 20—The effects of additional wind power. A number of participants asked questions related to the impact on the grid of new wind power, particularly in the Northeast Kingdom. Questions and comments included:

- Why can generation be detrimental to the system in some areas?
- Concern expressed about the impact of wind development on Vermont's natural environment.
- Concern expressed about the intermittent nature of wind making it unreliable.
- If the northern tier lacks the capacity to handle additional generation, why are wind developers still proposing projects in the Northeast Kingdom?
- Why if the price of power in the market is depressed are developers seeking to build wind generation?

Response: As discussed on page 39 of the Plan, generation can have both negative and positive effects on the electric grid, depending on its technology, size and location. VELCO's role requires us to provide objective evaluations of all proposed projects seeking to interconnect with the transmission system. Any significant negative impacts caused by a proposed generation project are required to be resolved and financed by the developer.

Glossary & Abbreviations

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.

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.

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."

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 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.

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 mechanical power from an engine, a water wheel, a windmill, or other source, into electrical power.

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.

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.

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.

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.

subtransmission—Subtransmission 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—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.

Abbreviations

DPS	Vermont Department of Public Service
FERC	Federal Energy Regulatory Commission
FCM	Forward Capacity Market
HQ	Hydro Québec
HVDC	High voltage direct current
ISO-NE	ISO New England
MW	Megawatts
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
OATT	Open-Access Transmission Tariff
PSB	Vermont Public Service Board
PSNH	Public Service of New Hampshire
SPEED	Sustainably Priced Energy Enterprise Development
VEIC	Vermont Energy Investment Corporation
VJO	Highgate Vermont Joint Owners
VY	Vermont Yankee
VSPC	Vermont System Planning Committee