2015 Vermont Long-Range Transmission Plan

June 25, 2015

vermont electric power company

VELCO

Message from VELCO CEO Tom Dunn

A grid reformation is underway. How we generate, move and use power—and how we pay for it—are undergoing change at a rate not seen since Edison. Some utility leaders see this dynamism as a threat, some an opportunity and others a mixed bag. Transmission's role in this reformation—expensive relic in need of discard, or essential link to cost-effective, low carbon resources, or some of each—is under ongoing debate. Regardless of one's view, however, reliability remains a prerequisite.

Vermont Electric Power Company (VELCO) constructs, owns and operates our state's electric transmission system and must maintain the integrity of this critical infrastructure. State law and Public Service Board Order require VELCO to plan for Vermont's 20-year transmission reliability needs, updating this Plan every three years. The legal requirements for the Plan focus on our central mission: planning for electric system reliability as measured by mandatory standards set by the North American Electric Reliability Council (NERC). But this central task is set against an increasingly complex backdrop of regional and national trends that are captured in the discussion you will find in the 2015 Vermont Long-Range Transmission Plan.

This 2015 Plan reflects the changes underway in the power system and the uncertainty those changes produce. The central task of this plan remains unchanged: identify where load growth or other changes may result in the need for system reliability investments, and share that information in sufficient time to consider alternatives to building poles and wires. But while that task seemed relatively straightforward in 2006, when our reliability planning system was written into Vermont law, today it is far more complex.

We used to predict future electric demand in terms of simple growth curves. Today a myriad of variables challenge assumptions about growth: exponential increases in distributed renewables, retirements of base load, fossil-fueled and nuclear generation, an unsettled economy and innovation accelerators, like heat pumps and electric vehicles.

Beyond the challenges of load forecasting, whole categories of transmission other than reliability-driven projects —elective projects, merchant and public policy-driven transmission—are now under active discussion, but have not, to date, actually been built. And FERC Order 1000 has introduced competition to transmission construction in ways that will become clearer during the three-year life of this Plan.

In short, the task of transmission planners is far more complex than it has ever been, and presents opportunities for utilities and Vermont that, together, we can identify and seize over time. As we have seen from our previous collaborative successes in deferring over $150 million in transmission projects, this Plan is part of the foundation for securing that advantage.

My colleagues and I at VELCO are excited about the promise and the possibilities for transmission to help create and serve an energy future consistent with our company's and Vermont values. Vermont really is an energy innovation workbench, and I see innovation as a key element of ensuring future system reliability.

Thank you for taking the time to read and consider the 2015 Vermont Long-Range Transmission Plan and what it portends for our state and region. Many have worked hard on this document to make it as informative, readable, and up-to-date as possible. Above and beyond regulatory requirements, our intent is to foster dialogue and conversations as one important contribution to Vermont's public engagement on energy issues and policy.

Tom Dunn
CEO & President

Table of Contents

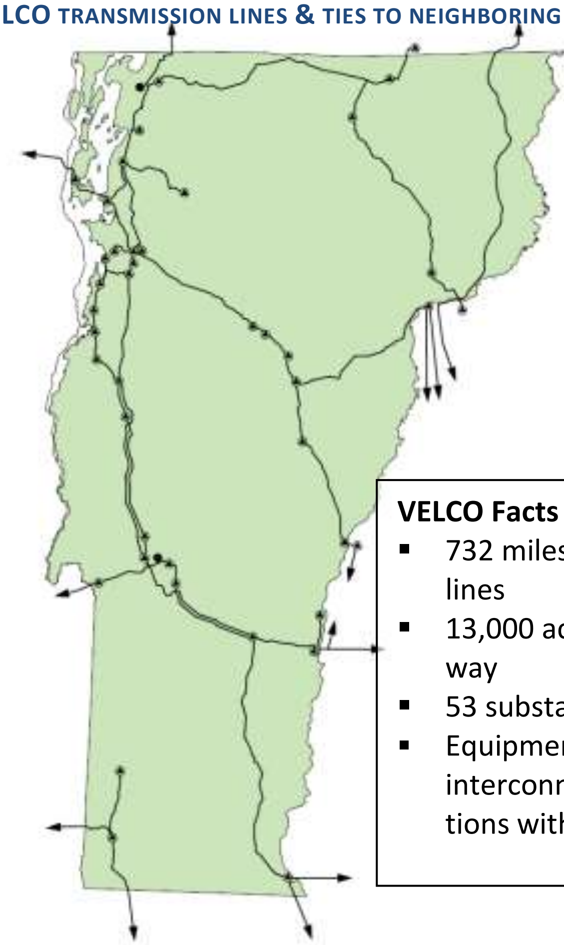
[This page deliberately left blank]

Introduction

Vermont law and Public Service Board (PSB) Order require VELCO to plan for Vermont's long-term electric transmission reliability, share our plan with Vermonters and provide an update every three years. The Plan's purpose is to ensure Vermonters can see where Vermont's electric transmission system may need future upgrades and how those needs may be met through transmission projects or other alternatives. Ideally, the plan enables all manner of interested people—local planners, homeowners, businesses, energy committees, potential developers of generation, energy efficiency service providers, land conservation organizations and others—to learn what transmission projects might be required and how and where non-transmission alternatives, such as generation and energy efficiency, may contribute to meeting electric system needs at the lowest possible cost.

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 the region's five 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 2015 Vermont Long-Range Transmission Plan—the Plan—is the third three-year update of the Vermont 20-year plan, originally published in 2006 and updated in 2009 and 2012. Much has changed since 2006. ISO-NE began operation as FERC's designated Regional Transmission Organization for New England in 2005. Since then, ISO-NE has continually refined its regional planning process, and added staff, as it has assumed the planning authority it was granted by FERC. Also during this period, more rigorous, binding performance standards for the high-voltage electric transmission system, and penalties for non-compliance, were authorized by Congress in response to the blackout of 2003, and adopted by NERC, NPCC and ISO-NE in 2007. These changes require that Vermont's planning process coordinate very closely with the regional planning work managed by ISO-NE. In 2014, ISO-NE completed its most recent study of the Vermont/New Hampshire area 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.

Given ISO-NE's regional planning responsibilities, resources and expertise, 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 about four percent of the region's electric demand.[1] VELCO's refinement of ISO-NE's analysis articulates the reliability issues in a manner that facilitates 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, and conducted a more extensive evaluation of non-transmission alternatives.

The 2015 Plan acknowledges a profound transformation of the electric grid that has begun in the past several years. Many changes that are underway or on the horizon challenge reliable operation as the system has traditionally been designed and operated, and provide promising opportunities for new utility models and a more diverse grid. Key factors in the current transformation include retirement of traditional, base load generation, an increase in distributed renewable resources, greater investment in demand-side resources such as energy efficiency and demand response, and the impact of technological trends such as heat pumps and electric vehicles. These trends have been reflected in the load forecast used for the 2015 Plan. The Plan includes narrative discussion of those trends that cannot yet be quantified with confidence.

The results presented in this Plan show the reliability needs on Vermont's high-voltage, bulk electric system[3], which are presented beginning on page 23. Predominantly bulk system issues begin on page 27 and sub-system issues follow, on page 30. For each area, the Plan discusses the potential to address each issue with non-transmission solutions. 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.

[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.

Issues addressed since the 2012 plan

The 2012 Plan identified four major bulk system reliability concerns and seven predominantly bulk reliability concerns. The plan also identified several subsystem issues to be further investigated by the distribution utilities. Some previously noted issues have been resolved by planned upgrades. Other concerns have been postponed by lower-than-anticipated load levels.

The load forecast now projects lower peak demand than was forecast in 2012. Reasons include the lingering effects of the recession, load reductions due to ongoing energy efficiency programs, demand response, and the net effect of small-scale renewable generation. The retirement of the Vermont Yankee nuclear generating plant (VY) contributed to the deferral of certain identified transmission upgrades, but also raises potential concerns related to the retirement of base load generation in general and the increasing dependence on natural gas.

The table below shows how the reliability concerns identified in the 2012 Plan have been addressed or deferred. *(For 2012 bulk system concerns, please refer to pages 19-29 of the 2012 Plan. For predominantly bulk system concerns see pages 30-36, and for subsystem issues see pages 37-38.)*

DISPOSITION OF RELIABILITY ISSUES IDENTIFIED IN 2012 PLAN

Item identification *Page #s refer to 2012 Plan*	**Identified deficiency**	**Resolution or deferral of concern**
Southeast Vermont *Pages 20-21*	Line exceeded its current carrying capacity for an N-1-1 condition	Deferred by retirement of VY and lower forecasted load levels
Central Vermont* *Pages 24-26*	Low voltage; several facilities exceeded their current carrying capacity for an N-1-1 condition	Deferred by retirement of VY and lower load levels
Northwest Vermont *Pages 27-29*	Low voltage; several facilities exceeded their current carrying capacity for an N-1-1 condition	Deferred by lower forecasted load levels
St Albans and East Fairfax area *Page 31*	Low voltage; overloads	Transformer added and associated subsystem upgrades installed at Georgia substation
Hartford area *Page 33*	Low voltage	Resolved by load transfer, addition of capacitor bank, and line upgrades (under various stages of permitting and construction)
IBM area *Page 35*	Loss of load	Mitigated by line protection
Vernon Road *Page 36*	Loss of load	Breakers added at Vernon Road

** A line overload was identified in the Central Vermont area at load levels above 1030 MW in 13 years based on the current forecast. Maintaining the load below 1030 MW will continue to defer transmission upgrades in the Central Vermont area.*

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 reflect specialized professional skill, such as forecasting electric usage. Still others rely on understanding evolving trends in the industry and society. Some of these factors involve greater uncertainty than others and involve longer or shorter time frames. The following section discusses some major assumptions or parameters reflected in the 2015 Plan.

Mandatory reliability standards

The criteria used to plan the electric system are set by the federal and regional reliability organizations, NERC[5], NPCC[6], 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 under three kinds of conditions.

1. All facilities in service (no contingencies; expressed as N-0 or N minus zero).
2. A single element out of service (single contingency; expressed as N-1 or N minus one).
3. Multiple elements removed from service (due to a single contingency or a sequence of contingencies; expressed as N-1-1 or N minus one minus one).

In the N-1-1 scenario, planners assume one element is out of service followed by another event that occurs after a certain period. After the first contingency operators make adjustments to the system in preparation for the next potential event, such as switching in or out certain elements, resetting inter-

---

[4] VELCO uses Siemens PTI Power System Simulator for Engineering (PSS/E) and GE's "positive sequence load flow" or PSLF software.

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

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

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.

Reliability standards set by NERC continue to evolve in a more prescriptive direction that will further reduce discretion about how to analyze the system and what solutions are compliant with regional and federal regulations. A new planning standard, which was approved since the last long-range plan, will replace several planning standards.[7] Some of the requirements of that new standard became enforceable in January 2015 and others will go into effect in January 2016. ISO-NE's studies using the new standard have identified system upgrades that will be necessary to comply in the future; however, declining Vermont loads will likely minimize or avoid in-state system upgrades, assuming system conditions and operation protocols do not change significantly.

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. Summer peak and winter peak loads were analyzed in this long-range plan.

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 nameplate capacity of intermittent generators is discounted based on historically validated expected performance during the summer peak hour and winter peak hour. For instance, wind generation is discounted to 5 percent of its nameplate capacity, and hydro generation is discounted to 10 percent of its audited capacity to represent their expected production during summer peak load conditions. The corresponding winter peak production is discounted to 25 percent for both hydro and wind generation. Peaking generators that can get to full output within 10 minutes were modeled at 70 percent of nameplate capacity, which is greater than historic performance of Vermont peaking generation.

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 the 2015 long-range plan studies.

[7] The previous NERC TPL standards can be found at:
http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States
and the recently approved TPL standard can be found at:
http://www.nerc.com/pa/Stand/Pages/StandardsSubjecttoFutureEnforcement.aspx?jurisdiction=United States

ASSUMPTIONS REGARDING PLATTSBURGH-SAND BAR IMPORTS ALONG EXISTING FACILITIES.

The flow of power from New York to Vermont over the Plattsburgh-Sand Bar transmission tie was modeled at or near zero megawatts (0 MW) pre-contingency. System constraints in New York have led New York to request that studies assume 0 MW will flow over the tie, and that, under certain conditions, Vermont will export to New York. This assumption is more conservative in cases where insufficient capacity exists to serve load. The recently completed ISO-NE 10-year study found no system constraints aggravated by the tie flow at 0 MW.

ISO-NE VERMONT/NEW HAMPSHIRE NEEDS ASSESSMENT THE BASIS FOR THE 2015 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 ISO-NE, supplemented to meet the requirements of the planning process approved by the PSB in Docket 7081. The additional considerations in the Plan include analysis of the transmission system beyond the 10-year horizon, analysis of the sub-transmission system, analysis of winter peak conditions, a Vermont-specific load forecast, and a more extensive evaluation of non-transmission alternatives. The Vermont 10-year summer peak transmission analysis was performed by ISO-NE, in collaboration with VELCO and 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 propose alternative solutions that may include demand reduction measures and additional supply, all of which influence ISO-NE's overall Regional System Plan.

- 6.5 million households and businesses; population 14 million
- Approximately 350 generators
- Approximately 31,000 MW of total generation for 2014
- Over 8,500 miles of transmission lines
- 13 interconnections to electricity systems in New York and Canada
- Approximately 2,100 MW of demand resources for 2014
- All-time peak demand of 28,130 MW, set on August 2, 2006
- Approximately 500 participants in the marketplace (those who generate, buy, sell, transport, and use wholesale electricity and implement demand resources)
- Market value in 2013:
  - $8.82 billion total
  - $7.49 billion energy market
  - $1.06 billion capacity market
  - $0.27 billion ancillary services market
- Approximately $6.5 billion in transmission investment since 2002; approximately $4.5 billion planned

KEY FACTS ABOUT NEW ENGLAND'S ELECTRIC POWER SYSTEM AND WHOLESALE ELECTRICITY MARKETS

Source: ISO-NE 2014 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 load level predictions, generation, system topology, technological developments, changes to planning standards, and changes to public policy that impact how the transmission system will be utilized. This report reflects VELCO's 20-year analysis; however, the main focus is on the 10-year period through 2025. Results beyond 10 years were used to examine system performance trends, evolving system needs, the effects of increased demand, and longer-term solution options. This approach was reviewed with the Vermont System Planning Committee (VSPC).[8]

LIMITATIONS IN THE SCOPE OF THE PLAN

The projects covered in this Plan include transmission system reinforcements that meet the definition contained in Docket 7081. As such, the Plan may not include all transmission concerns that must be addressed in the coming period. VELCO sought input in multiple phases during its analysis to identify all load-serving concerns that may require system upgrades; however, some concerns may not have been identified due to insufficient information, unforeseen events, new requirements or the emergence of new information.

In addition, from time to time, VELCO must make improvements to its system to replace obsolete equipment, make repairs, relocate a piece of equipment, or otherwise carry out its obligations to maintain a reliable grid. Sometimes these activities require significant projects, such as the refurbishment of substation equipment and the replacement of transmission structures to replace aging equipment or maintain acceptable ground clearances. The Plan does not include such projects that are needed to maintain the existing system, though VELCO routinely shares plans for many of these projects with the VSPC as part of its "non-transmission alternatives" (NTA) project screening process. The formal NTA screening tool[9] employed in this process "screens out" projects that are deemed "impracticable" for non-transmission alternatives because they are specifically focused on resolving asset condition concerns. At this point, it is expected that most of those projects do not require the filing of a certificate of public good because the conditions for a filing have not been triggered.

The following list identifies currently identified significant VELCO projects to address asset condition:

- Substation refurbishment projects at Windsor, Barre, Berlin, Florence, Sandbar, Newport and St. Albans
- Essex STATCOM replacement, Essex
- Transmission Structure Replacement Program, statewide
- PV20 Cable Replacement, Grand Isle

---

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

[9] The NTA screening tool used to screen bulk transmission and subtransmission issues is posted at http://www.vermontspc.com/nta-screening .

Similarly, elective transmission—projects paid for by developers for the purpose of bringing power to markets—and the impact of new generation projects on the transmission and sub-transmission systems are generally beyond the scope of this reliability-focused plan. Elective transmission, generation changes, and their associated upgrades are modeled once the requisite regulatory approvals have been obtained and it is clear that they will become operational.

Impacts of grid transformation on essential reliability services

In the past several years, a profound transformation of the electric grid has begun, which challenges reliable operation as the system has traditionally been designed and operated. Many base load, conventional generators are retiring due to the high costs of complying with more stringent emission standards, public concern regarding nuclear energy, decline in natural gas prices leading to increased gas generation, and rapid growth of small-scale intermittent renewable generation reducing electric demand on the grid. In the past, these conventional generators were the mainstay of the power grid, which was designed to depend on them for reliability. NERC has identified six essential reliability services that these retirements are eroding:

- Operating reserve
- Frequency response
- Ramping capability
- Active power control
- Reactive power and voltage control
- Disturbance performance

Legitimate concern within the power industry rests on the effects of base load plant retirements, compounded by the replacement of conventional generation with intermittent renewable generation, which almost exclusively utilizes electronic technology to connect to the grid. The Plan does not include any specific system upgrades associated with the integration of renewable energy, but it is worth noting that, unless the interconnection rules are updated, we are unlikely to capture the full value of renewable energy to the grid even as essential reliability services may continue to decline. In the near- to mid-term, VELCO predicts significant voltage regulation issues. Mitigation of voltage regulation concerns already consumes more than 20 percent of VELCO system operators' time, a trend that will likely increase. The ability of small-scale renewable generation to displace larger conventional generation, including gas, coal, and oil-fired generators, depends upon incorporating deliberate protection and control designs that exist in conventional generation and that renewable resources can approximate to various degrees, but are unlikely to do so unless required. Revision of interconnection rules provides the opportunity to secure some of these reliability benefits and to assure future system stability. Reliable grid operation requires standards of performance for small-scale renewable generation during and immediately after disturbances. To perform adequately, these resources need the ability to adjust control set points including:

- Primary frequency response (governor response)
- Low- and high-frequency ride-through
- Low- and high-voltage ride-through
- Reactive power and voltage regulation
- Ramp rate control
- Soft start capability
- Disconnection in an emergency or line outage
- Low harmonic generation content of the inverter

Currently, VELCO and ISO-NE operators have no real-time monitoring and control of small-scale renewable generation. As this type of generation increases, operators must know how much small-scale generation is running and how it will behave under changing system conditions. Little operations and planning data about these installations are currently available to VELCO in any statewide database. Such a database is needed and should address: the technology utilized, the DC and AC nameplate capacity, the inverter settings with respect to grid services, any protection settings, and geographic and electrical location.

Since the Vermont grid is part of an interconnected system, any interconnection standard revisions in Vermont must coordinate, to the extent possible, with other states' regulators and ISO-NE.

Funding for bulk system reliability solutions

Because Vermont is part of the interconnected New England grid, bulk system transmission solutions in Vermont that are deemed by ISO-NE to provide regional reliability benefit are generally funded by all of New England's grid-connected customers with Vermont paying approximately four percent of the cost based on its share of New England load. Likewise, Vermont pays four percent of reliability upgrades elsewhere in New England. Facilities subject to regional cost sharing are called Pool Transmission Facilities or PTF. Most of the 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 more than a decade. Since 2008, through the creation of a regional energy market called the Forward Capacity Market (FCM), providers of generation and demand resources (energy efficiency and demand response) are compensated through regional funding for their capacity to contribute to meeting the region's future electric demand. These capacity supplies may reduce the need for building transmission if properly located with respect to transmission system capacity and local load levels. Since capacity and energy resources are part of a competitive market, development funding of those resources is paid by the resource developer. This is different from the funding mechanism of reliability-based transmission upgrades where those upgrades are funded by all distribution utility customers pursuant to the region's transmission tariff. Separation between markets and transmission is a basic principle in current FERC rules, which creates a barrier to regional cost sharing of non-transmission alternatives, even when they are more cost-effective than a transmission upgrade. Vermont continues to advocate regionally for funding parity among transmission and non-transmission options to ensure the most cost-effective alternatives can be chosen to resolve a system constraint.

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 2015 analysis takes into account any new generators that have a capacity supply obligation, either through the ISO-NE FCM or through bilateral contracts. Conceptual or proposed projects were not considered. Historically many proposed generation projects ultimately withdraw their interconnection requests due to financial difficulties, permitting, local opposition, inability to find customers and other factors. Since the 2012 Plan, two wind generation projects have been completed for a total of approximately 75 MW, three projects for a total of approximately 190 MW withdrew their interconnection requests, and one ~40 MW project was rejected by the Vermont Public Service Board. Nearly 185 MW of proposed generation remain in the ISO-NE generation interconnection queue, 80 percent of which consists of wind generation, which provides reliability benefits up to five percent of its maximum capacity, and 20 percent of which consists of biomass generation. Necessary studies have been completed on the biomass project since June 2011. Planned generation projects that have received ISO-NE approval and have a capacity supply obligation in the market were modeled in service.

No "Elective" transmission, or market-related projects in the Plan

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

While elective transmission can have an impact (positive or negative) on the reliability of the system, no elective project was assumed to have been completed during the Plan analysis because no such project has yet progressed to the point that its completion is certain. Although a number of projects that are considered elective transmission are in various stages of discussion, development and permitting, at the time of this writing, no project has received approval from ISO-NE nor the PSB.[10]

Regional attempts to address gas supply constraints and carbon policy

New England's power grid faces significant supply-related challenges. Electricity prices are highly volatile due to the region's growing dependence on natural gas-fired generation, including dual-fuel generators. Until remedied, ISO-NE projects that constraints in gas supply will pose a large risk to both price and supply adequacy during the coldest days of winter. A large amount of fossil fuel generation is retiring as discussed above. The region's six states all have goals for reducing carbon emissions from electric supply and renewable supply is available to our west in New York State and to our north in Canada.

To address these issues, the New England Governors in 2014 proposed the New England Governors' Infrastructure Initiative (GII), which included a gas pipeline and electric transmission for power imports to the region. The complex initiative included a novel concept, likely counter to FERC rules, of funding gas infrastructure with electric ratepayer dollars. As proposed, GII ultimately died as a result of failure in July 2014 of Massachusetts state legislation necessary to the effort. At this writing, some states were continuing, after the Massachusetts bill failed, to craft a more limited cooperative initiative to expand transmission for access to new, low-carbon supply. Large rate increases to cover spikes in power costs, some above 25 percent, were already being implemented in southern New England going into the winter of 2014-2015. While Vermont's power supply is currently largely insulated by longer-term contracts from this price volatility, high power costs in the region as a whole have significant impacts on the region's economic competitiveness, as well as supply adequacy.

FERC issued an order in September 2014 approving ISO-NE tariff changes to implement a temporary out-of-market solution intended to maintain reliability. The reliability program for winter 2014-2015 is designed to ensure adequate fuel supplies by creating incentives for dual-fuel resource capability and par-

[10] One elective transmission project proposed to be built in Vermont was pending at the PSB at the time of publication: the New England Clean Power Link, proposed by TDI New England. See http://necplink.com .

ticipation, offsetting the carrying costs of unused firm fuel purchased by generators, and providing compensation for demand response services.

Electric grid planners and operators are becoming concerned about the potential impacts of the growing gas dependency on the electric grid reliability. The Eastern Interconnection Planning Collaborative (EIPC) has received funding from the U.S. Department of Energy (DOE) to perform an analysis of the interactions between the gas and electric systems in a broad-based, transparent, collaborative process with the involvement of various stakeholders and six planning authorities in the eastern interconnection with ISO-NE as a principal investigator. The analysis has been completed and results of the analysis will inform policy deliberation by state, provincial and federal policy makers and other stakeholders.

In March, 2015 the region received a FERC order approving the region's FERC Order 1000 compliance plan, which required among other things a mechanism for regional cost-sharing for transmission projects built to meet public policy goals. The FERC order approved New England's proposal, which provides for socialization of 70 percent of the cost of transmission projects built for such purposes as meeting carbon reduction targets.

Against this backdrop, multiple developers have already proposed several large transmission projects that are in various stages of study and permitting. Since these proposals are rapidly emerging and proceeding through applicable regulatory process, no attempt is being made to summarize their status here.

LOCAL RESOURCES

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

Vermont Yankee

The VY nuclear plant was modeled out of service in the entire analysis because of its retirement in December 2014. With VY retired, the largest Vermont generator is a 65 MW wind plant near Lowell.

The Highgate Converter

The Highgate Converter is the point at which energy flows from Hydro Québec (HQ) to Vermont's electric grid. The converter can carry the full amount contracted between HQ and the Vermont utilities during all hours of the year except periods of high demand that can affect the HQ system. Recent upgrades on the HQ system will allow the converter to operate at full capacity during all summer hours.

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 increases exposure to 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 is the 50 MW McNeil wood burning unit. 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. In Vermont's case, McNeil and the Berlin gas generator were modeled out of service.

Vermont peaking power

ISO-NE's 10-year analysis counted 80 percent of peaking power capacity, however, historical data shows actual performance below this level. Fifteen Vermont generators with a nameplate 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 ISO-NE 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. The Vermont peaking units for the past ten years have performed well below the 80 percent assumption during emergency conditions. While recent market changes, specifically a program called Pay-for-Performance, may increase performance, it is also possible that some of these units may leave the market if they see penalty risks as too high. For these reasons, VELCO modeled 70 percent of peaking power capacity for purposes of this long-range plan.

Hydro and wind power

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

Small-scale renewable generation

State policy, grant funding, federal tax incentives and robust organizing and advocacy have greatly increased the amount of small-scale generation on Vermont's distribution system. The legislature in 2012 and 2014 adopted proposals that further expand state incentives for small-scale renewables. Two programs—net metering[11] and SPEED Standard Offer Program[12]—are assuring a market for the output of small scale renewables. Vermont utilities are currently required to buy the yearly output from net metered customers at $0.19/KWh, or $0.20/KWh for projects 15kW or less, up to a ceiling of 15 percent of the state's demand, or approximately 150 MW. As of September 2014, the PSB has permitted approximately 60 MW of net metering capacity.

In 2009, the Standard Offer program was oversubscribed for its 50 MW cap. In 2013, the PSB modified the program to establish an annual solicitation at a pace dictated by statute, gradually increasing to 127.5 MW over the next decade. As of late 2014, approximately 45 MW of Standard Offer resources were in service, mostly solar and methane.

---

[11] 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.

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

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 100 local energy committees in Vermont communities are considering community-based renewable development programs.

Since the 2012 Plan, the potential reliability benefits of small-scale renewable generation have become increasingly evident. For example, the utilities conducted a Non-Transmission Alternatives (NTA) study for the Central Vermont system constraint identified in the 2012 Plan and determined that small-scale renewables, combined with energy efficiency and demand response, could contribute sufficient capacity to permit deferral of system upgrades with some supplemental resources. This information was shared with ISO-NE and regional stakeholders and contributed to formation in 2013 of ISO-NE's Distributed Generation Forecast Working Group. In the spring of 2014, ISO-NE, with the assistance of regional experts, developed the first distributed generation (DG) forecast for New England. ISO-NE has proposed a new methodology for modeling DG in transmission planning studies and further use may be made of the DG forecast in the future. Based on ISO-NE's proposed methodology, DG projects that have provided notification to ISO-NE via a Proposed Plan Application (PPA) or have received a PPA approval will be modeled explicitly as a negative load if less than 5 MW or as a generator if greater than 5 MW. DG that is not visible to ISO-NE will be modeled as negative load applied homogeneously to all load stations. Because this issue was emergent at the time of the ISO-NE study on which this Plan is based, DG was not yet modeled explicitly; however, in this long-range plan, the load forecast was reduced by the amount of expected net metering and Standard Offer as forecast by Itron, the SPEED administrator and the VSPC.

Vermont as a net importer

Historically, large portions of Vermont have been net importers of electric power. Mathematically, the state has had enough generation; however, due to the performance characteristics of the in-state generation, Vermont has relied heavily on its transmission network to import power from neighboring states. As of 2015, following the shutdown of Vermont Yankee, Vermont will become a net importer of power at virtually all hours from New York, New Hampshire, Massachusetts and Canada in order to meet the state's load requirements. Without significant new in-state generation, this situation will be a long-term operating condition.

Forecasting demand

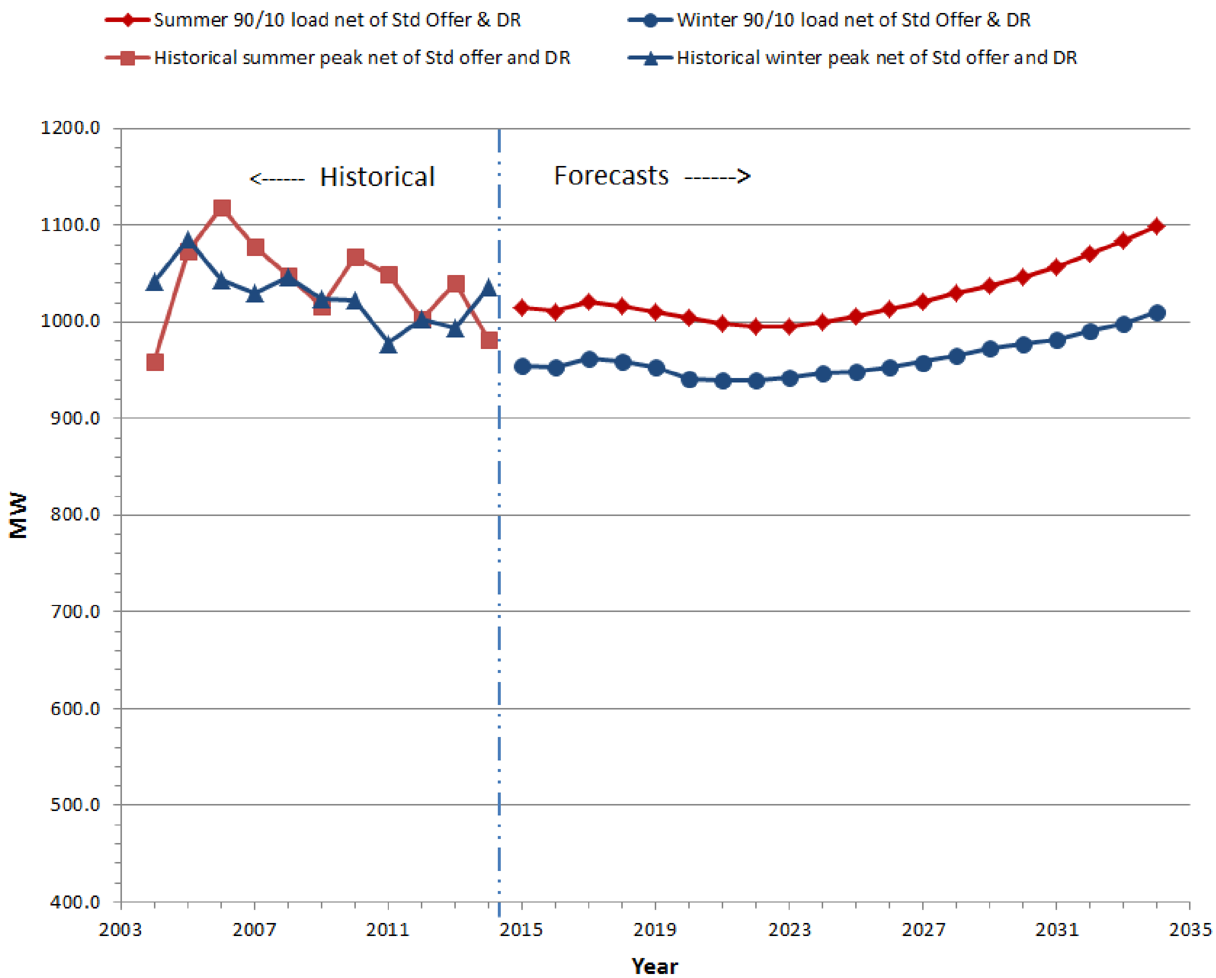
The forecast of future demand for electricity is a critical input in electric system planning. The forecast determines where and when system upgrades may be needed due to inadequate capacity.

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 and small-scale renewable energy. The following section summarizes the forecast underlying this Plan. More detailed information about the forecast can be viewed at *http://www.vermontspc.com/2015-forecast* .

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 the effects of energy efficiency, demand response, the Standard Offer and net metering programs, and future load increases due to heat pumps and electric vehicles. The forecast projects summer peak load levels in 2015, 2025 and 2034 of 1015 MW, 1005 MW and 1100 MW, respectively. The corresponding winter peak load levels are 955 MW, 949 MW and 1011 MW, respectively. The forecast projects that load reduction measures will decrease the summer peak load for at least ten years, but future heat pump and electric vehicle loads will start to increase the load to the point where the summer peak load will return to the 2015 forecast load level after 11 years. The summer peak load will return to the historical 2013 load level after 14 years, and the 20-year summer peak forecast will not reach the historical all-time peak load set in 2006. This forecast was used to determine the timing of reliability deficiencies in this 2015 Plan update.

Historical and projected Vermont peak load

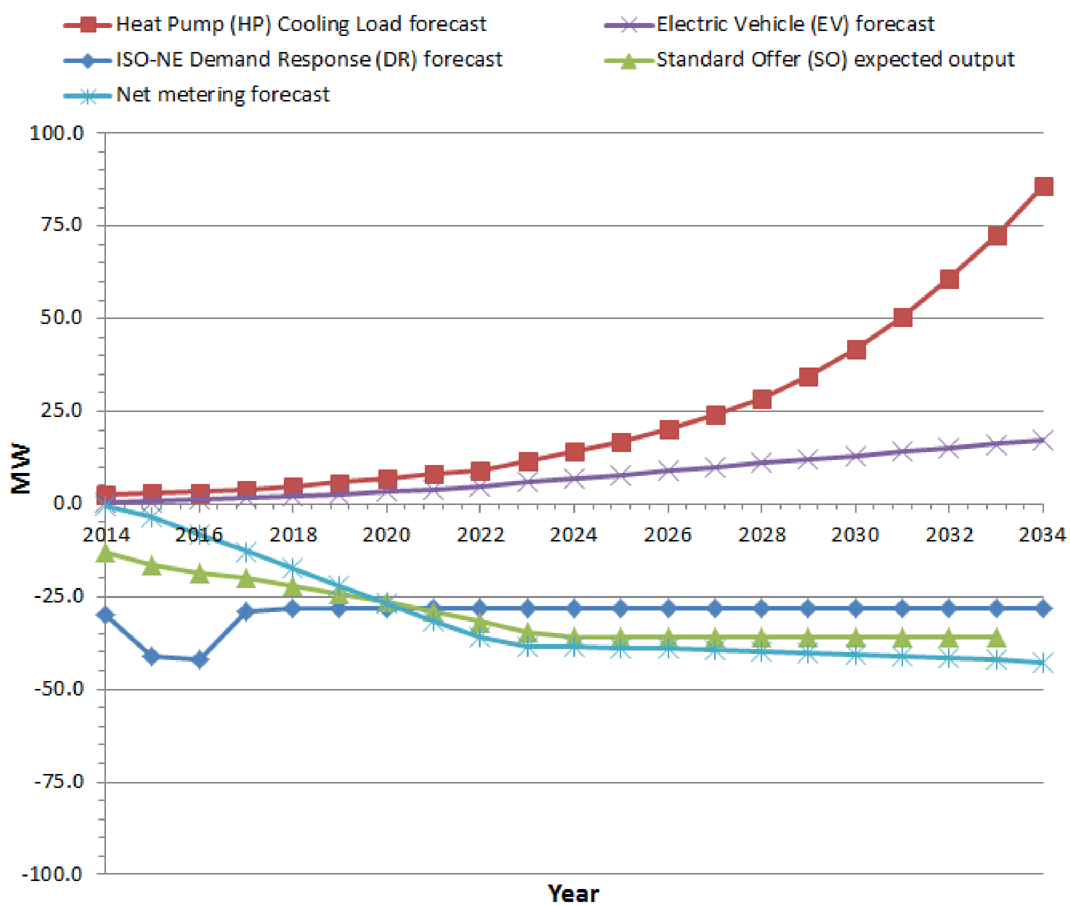


Forecasting for this Plan was completed in October 2014 by ITRON, an energy firm that offers highly specialized consulting expertise in load forecasting, under contract with VELCO. In developing the forecast, ITRON incorporated the latest energy efficiency projection in collaboration with the Vermont Public Service Department (PSD), the Vermont Energy Investment Corporation (VEIC) and the VSPC, which includes representatives of the distribution utilities and the public.

Future electrical demand can be estimated very simply by drawing a straight line across historical peak loads. This method may be valid where the rate of load growth has been fairly stable (no more than a few percent annual growth), the amount of load in question is very small and the forecast period very short, as in one year. This method is typically employed when forecasting load on a distribution feeder. As shown in the historical graph above, a straight line progression would be an inadequate forecasting method for the transmission system. For the five years prior to 2006, a straight line projection would produce a 20-year load forecast with a 1.7 percent growth rate. Between 2006 and 2009, a straight line projection would result in a decreasing 20-year load forecast at a rate of 1.5 percent. Itron employs an end-use model that essentially forecasts each element, e.g., lighting, heating, cooling, and so on, that contributes to the overall load forecast. Regression analyses are then performed to capture the effects of economic, weather, and other factors on energy consumption and peak demand.

Development of the current forecast was particularly complex, but Vermont's collaborative approach also contributes to a reasonably robust forecast that is understood and supported by a wide array of Vermont stakeholders. The 2015 forecast includes several significant changes compared to the 2012 forecast. Similar to the previous forecast, the load forecast model captured a portion of the ongoing energy efficiency, but the percentage has changed. The most recent analysis determined that the load model captured 80 percent of residential sector efficiency, compared to 50 percent in the 2012 analysis, so the 2015 Plan applies 20 percent of the forecasted energy efficiency to future loads to avoid double counting of energy efficiency effects. As more time passes, a greater proportion of ongoing energy efficiency will be captured by the model. Energy efficiency is embedded in the load, therefore is not plotted separately in the graph below.

VERMONT LOAD FORECAST COMPONENTS



For the first time, the load forecast modeled the effects of a new technology—high-efficiency heat pumps, also called cold weather heat pumps, which can provide heating at temperatures below 0° F at greater efficiency than several other heating sources. This new technology will allow the state of Vermont to meet its renewable energy goals, outlined in the most recent state energy plan, by replacing relatively high-carbon heating sources with electricity, which is becoming increasingly clean with the installation of small-scale and utility-scale renewable generation. High-efficiency heat pumps are likely to have several effects. First, though they are a more efficient heat source than other alternatives, they will shift some heating load back to electricity after a long-term trend away from electric heat. Second, while cold weather heat pumps can function at low temperature, supplemental carbon-based heating will be required at times of extreme cold (and therefore extreme load), meaning that shifting to heat pumps will not completely displace oil, wood or gas heat. Third, the ability to cool with the same high-efficiency equipment will tend to be additive to the existing cooling load, and it is this heat pump cooling load that is projected to significantly increase summer peak load after 10 years. The heat pump summer load projection is consistent with the forecast used by Green Mountain Power (GMP) in its Integrated Resource Plan, and is projected to be 17 MW and 86 MW in 2025 and 2034, respectively, while the corresponding winter figures are 9 MW and 46 MW. These projections represent best available information at the time of the forecast, but heat pump adoption remains an emerging trend with much uncertainty ahead.

For the first time, the load forecast models the effects of electric vehicles (EVs). This technology is evolving and is predicted to become a noticeable element of the load in the mid- to long-term. The electric vehicle forecast is based on available data from VEIC, Navigant and other sources. The number of electric vehicles (all-electric and plug-in hybrids) is expected to grow 20 percent annually up to 2024 and then at 2500 vehicles per year after that. In 2024, the forecast projects that three percent of all vehicles will be EVs. Electric vehicle load projections are based on an average charging load of approximately 2100 KWh per vehicle, and the assumption that most of the charging will occur in the evening, driven by an electric vehicle charging tariff. The summer or winter electric load is projected at 8 MW and 17 MW in 2025 and 2034, respectively.

For the first time, the load forecast modeled the effects of small-scale renewable energy from the net metering and Standard Offer programs. The previous 2012 forecast did not include these resources because their contribution was less than 1 MW annually. Starting in 2012, net metering and Standard Offer installed capacity have increased rapidly, driven by Vermont policies encouraging development of renewable energy, to the point of changing the behavior of the daily system load. As a result of these policies, Vermont has seen an explosion of photovoltaic (PV) generation, the predominant technology since 2012, with lesser contributions from wind, hydro, biomass, and methane.

As noted above, Act 170 of the 2012 Vermont Legislature increased the Standard Offer program cap from 50 MW to 127.5 MW, phased in between 2013 and 2022. Recent performance suggests the program is functioning as planned. Act 99, in the 2014 legislative session, increased the net metering cap from four percent to 15 percent of peak load. Some distribution utility service territories have already reached the four percent cap, and recent performance would suggest that the 15 percent cap will likely be reached in the near term.

Favorable financial incentives drive the net metering program successs as well as two relatively new aspects of program design: (1) group/community net metering, where multiple “customers” can share in the cost and benefit of larger PV projects; and (2) the increase in maximum size of net metering installations from 150 kW to 500 kW. A net metering facility can be as large as 5 MW under certain conditions, such as projects sited on a closed landfill or developed by a utility. The net metering forecast is based on GMP adoption data through April 2014, and the GMP group net metering forecast, but adjusted based on input from the VSPC forecasting subcommittee. The summer net metering production at the time of the summer peak is projected to be 28 percent[13] of installed capacity, resulting in 39 MW and 43 MW in 2025 and 2034 respectively. The summer Standard Offer production at the time of the summer daily peak is projected at 28 percent of installed capacity, or 36 MW, resulting in 2023 remaining constant beyond that date based on the currently scheduled end of the Standard Offer program, but this projection may change if the program is extended.

PV installation rates will likely vary across the state, and will depend on the availability of open land, the level of acceptance by local communities, and the policies and available system capacity of host utilities. VELCO will continue refining the forecast, in collaboration with the VSPC, to account for differences in small-scale renewable generation in certain areas of the state.

Although VELCO contracted for its own, independent forecast, the analysis that serves as the basis for this Plan is the ISO-NE 2023 VT/NH Needs Assessment, which is based on the ISO-NE 10-year load forecast. 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.

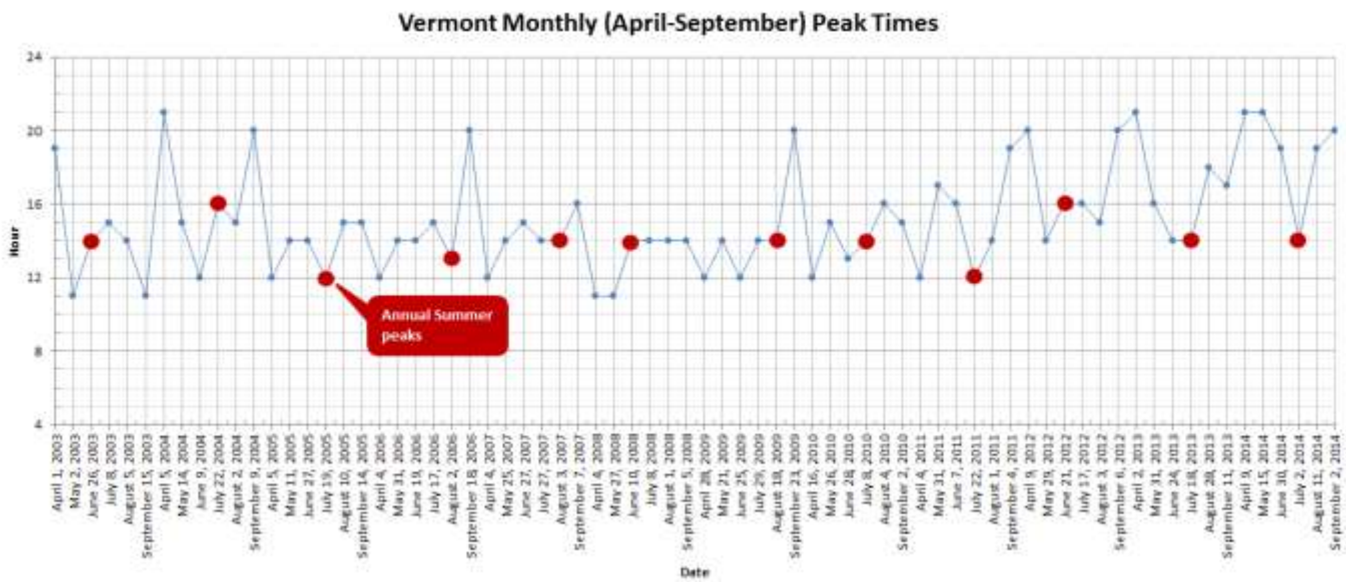
PEAK DEMAND TRENDS

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 actual 2014 summer peak was less than 1000 MW for the first time since 2004. The all-time 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 summer, but subsequently rebounded to 1068 MW in 2010 and 1050 MW in 2011 as the economy began to recover. Economic projections published by the experts, Moody Analytics and Woods & Poole, are critical inputs to the load forecast analysis. These experts have adjusted their projections over the years, but they all assume a fairly robust recovery in the long term to get back to the so called natural economic growth. These recent projections were reviewed by Itron and the VSPC, and they were adjusted downward as they appeared too aggressive, despite having been lowered over time.

The increasing adoption of small-scale renewable energy has begun to affect the daily behavior of the load. The timing of the peak hour in the load forecast has changed from 2 p.m. to 6 p.m., primarily because of the effects of solar generation. As the peak hour occurs later in the day, the contribution of solar generation during the peak hour is also reduced, from as high as 50 percent to approximately 25 percent. Very high penetration of solar generation will likely push the peak hour even later in the day or perhaps to early morning. VELCO will continue to monitor the impact of solar generation on the peak day, and future load forecasts will continue to take these effects into consideration. The following graph shows the progression of monthly peaks for the sunnier half (April to September) of the year. The timing of the peak for the months of October to March has occurred consistently at 6 p.m. or later, therefore is not plotted. The timing of the peak for April to September can occur early in the afternoon, as in the

[13] The Vermont load profile on a summer day is very flat, i.e., loads measured on either side of the peak hour are within five percent of the daily peak for six hours or more. Overlaying the shape of solar generation showed that the peak hour is moving to later in the afternoon where solar generation is less effective. That contribution was found to be approximately 28 percent.

summer months, or in the evening as in the winter months. The timing of the peak for the months of May to August has occurred consistently in the afternoon (2 p.m. plus or minus two hours). The small blue dots show the timing of the peak for each of these six sunny months since 2003, and the larger red dots show the timing of the annual summer peaks. A distinct shift of the monthly peak timing to later in the day can be observed starting in 2012 when a multifold increase in PV generation started to occur. In 2014, for the first time, May peaked at 9 p.m., June peaked at 7 p.m., and August peaked at 7 p.m. Only July, typically the month in which the annual peak occurs, has not peaked later than 4 p.m., but the timing of the July peak is likely to change as more PV is installed. The flatter the daily load shape, the greater the effect of solar generation on the timing. The timing of the July peak is not yet affected because solar generation needs to offset more of the 2 p.m. load for the 6 p.m. load to become the highest load for the peak day.



System planning analyses take the timing of the peak into account. The shape of the Vermont load curve on a summer peak day has traditionally been quite flat. Small-scale renewable energy is making the curve even flatter during the daily peak period (+/-2 percent around the peak), which can be six to eight hours. This transformation is relevant to the development of NTAs, such as energy efficiency and generation. An NTA that is proposed to address a summer peak problem potentially will need to be in service for eight hours or more. Renewable energy is not only affecting system planning, it is likely affecting the efficacy, i.e., the coincident factor, of energy efficiency measures at the time of the peak. For instance, if the current measures were designed to reduce a type of load from noon to 4 p.m., additional measures may be needed to also reduce the load from 4 p.m. to 8 p.m. Renewable energy and energy efficiency may very well work together, where renewable energy reduces daytime loads and energy efficiency nighttime loads.

Accounting for energy efficiency and demand response in the forecast

As noted above, 80 percent of ongoing energy efficiency is embedded in the load forecast. Itron applied only 20 percent of future energy efficiency to the load forecast in order to avoid double counting the effects of energy efficiency.

This approach is different from the ISO-NE approach where energy efficiency is forecast separately from the load and the amount is based on the energy efficiency that has cleared the ISO-NE forward capacity auctions plus future energy efficiency as estimated by the ISO-NE energy efficiency forecast working group. As a result of this approach, the load forecast utilized in ISO-NE studies tends to be significantly lower than the load forecast produced by Itron and the VSPC.

Similarly, ISO-NE's 10-year analysis included the effects of the demand response that cleared the last forward capacity auction; however, there is no mechanism to forecast demand response beyond the last forward capacity auction, as demand response varies based on market forces, and can leave the market easily at any time. For instance, the amount of demand response was forecast at 41 MW in the years 2015 and 2016, but 29 MW in 2017 and 28 MW in 2018 because a lower amount of demand response cleared the forward capacity auction in two succeeding auctions. In the 2012 long-range plan, demand response was kept constant at 41 MW beyond the last auction at that time even though it was unclear whether demand response would continue to increase. New market rules beginning in 2016, will obligate demand response to bid its price in the energy market, which may result in more frequent calls for participants to shut off their loads. Demand response may continue to leave the market due to performance fatigue, financial disadvantages, or some other reason, a prediction which has proved true in the last two auctions. Notwithstanding that potential future decline, demand response was kept constant at 28 MW from 2018 to 2034.

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 the expected influence of factors such as economic activity, price elasticity, population growth, new technology, efficiency, weather, and public policy on customer behavior using mathematical methods to predict demand. The complexity and uncertainty of these factors means the timing of load level predictions is inherently uncertain. Although load forecasters use various methods to minimize uncertainties, the longer the horizon the more uncertain are the drivers of customer demand, the resulting load forecast and, consequently, the timing of when reliability concerns will arise. Other factors contributing uncertainty include:

- The trajectory of economic growth in Vermont and the region is uncertain, especially beyond 10 years.
- Itron's load forecast is based on known information, including input provided by local distribution utilities as part of the forecast process. Some substation loads may or may not be present in the future, and their status can affect system performance. For example, the winter peak load in the Newport load zone can be 50 percent higher than the Itron forecast, depending on the amount of load at the Jay ski resort and whether currently absent load from one industrial customer is reinstated. The status of that one customer's load can trigger the need for a system upgrade.

- Energy efficiency may be more difficult or expensive to obtain over the long run as easier and less costly load reductions have already been achieved. The advent of small-scale renewable energy is having an impact on the timing of the peak. To the extent energy efficiency measures target specific load hours, current measures may become less effective, or their coincident factors may become less predictable due to the variability of peak load timing.
- New FERC and ISO-NE requirements for treating and paying demand response programs on par with generation introduce uncertainty regarding future participation rates and effectiveness of demand response for large customers who in the future will be called upon to curtail load based on the energy market rather than system events and conditions as in the past. Adding to the uncertainty, a federal appeals court last year rejected FERC's Order 745, which requires that demand response resources be compensated in the energy market equally with generators, finding that FERC's actions impermissibly strayed into the retail energy market where the states have sole jurisdiction. That case is currently pending a final appeal at the United States Supreme Court and the fate of Order 745 remains uncertain. A decision is expected in 2016.
- 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. The current load forecast includes an explicit forecast of electric vehicle load, which increased the state load by approximately 15 MW over 20 years. The forecast also includes a projection of high-efficiency heat pump load, which was unknown at the time of the previous long-range plan. This reinforces the belief that 20-year forecasts are likely too uncertain to be the primary basis for the long-range plan.
- Regional uncertainties may affect Vermont through its participation in the New England grid. Environmental regulations will likely impact New England's generation mix, and ISO-NE has previously projected the retirement of a large amount of New England generation due to market forces and environmental concerns. In fact, since the last long-range plan, more than 3000 MW have either retired or announced imminent retirements. New sources of energy, including imports and elective transmission, albeit regional resources, may affect the performance of the Vermont system, particularly for the period beyond 10 years. In fact, since the last long-range plan, as many as six import projects have been proposed to connect to various locations in Vermont. These import projects vary in size from 400 MW to 1200 MW. (See velco.com/projects for information about proposed projects.)
- Recently, renewable energy and small-scale distributed generation expanded dramatically. Amendments to Vermont statutes enacted in 2012 and 2014 will greatly increase generation developed through Vermont's Standard Offer and net metering programs over the next decade. The forecast maintains Standard Offer constant beyond 2023, as it is unknown whether and how the program will be expanded.
- 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. A new planning standard was approved since the last long-range plan, and will replace several planning standards. Some of the requirements of that new

standard will be enforceable in January 2015 and others in January 2016. ISO-NE has started to perform studies based on some of the new requirements and has found system upgrades necessary for compliance. Other requirements will likely result in the need for additional upgrades; however, declining loads in Vermont are likely to either minimize or avoid system upgrades within the state, assuming system conditions and operation protocols do not change significantly.

- The load forecast includes a spatial distribution of loads across Vermont by zone; however, several of the elements that affect loads could not be modeled from a zonal perspective at this time. Demand response, net metering, Standard Offer, electric vehicles and heat pumps were modeled without regard to zonal differences. This method may be appropriate for region-wide transmission studies, but will be too optimistic or pessimistic for local studies.

Act 56 of the 2015 Vermont General Assembly

Since the VSPC draft and public draft of this plan were circulated, the 2015 Vermont General Assembly enacted energy legislation that will substantially change the sources of electricity used in the state as well as future electric demand. Among the changes contained in the bill that are likely to alter Vermont's energy landscape are these requirements:

- Creation of a Vermont renewable energy standard. This provision was enacted to ensure Vermont Renewable Energy Credits (RECs) remain saleable in neighboring state's REC markets.
- Utilities will supply their customer load with 55 percent renewable energy by 2017 increasing to 75 percent by January 1, 2032.
- The amount of distributed generation (small-scale renewable resources) will be at least one percent of sales in 2017 increasing to 10 percent by January 1, 2032.
- Utilities will meet an "energy transformation target" of two percent of sales in 2017 increasing to 12 percent by January 1, 2032. This requirement can be met either by additional distributed renewable generation or by reducing fossil fuel consumption by their customers. An example of the latter could, for example, involve energy efficiency services or conversion of heating from lower efficiency fuels and technology to high-efficiency electric heat pumps.

It will take time to study the net effect of these changes on Vermont's load forecast. The Vermont planning community, and the Vermont System Planning Committee, will undertake that analysis in the coming year and beyond.

Transmission results

The following section presents the findings of the ISO-NE VT/NH Needs Assessment, supplemented with additional analysis 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 ISO-NE VT/NH 2023 Needs Assessment identified bulk system reliability issues in the Connecticut River area. This 2015 Plan also identified a bulk system reliability issue in the Central Vermont area, which is projected to occur beyond the 10-year study horizon based on the load forecast utilized in the Plan. The following table summarizes the bulk transmission system issues identified in the study for quick reference.

Summary of bulk system regional grouping & transmission solutions	Lead & affected distribution utilities	Estimated transmission project cost & (VT share)[14]	Screened in or out of full NTA analysis
Connecticut River Valley • Rebuild Coolidge-Ascutney 115 kV line and 46 kV lines • Rebuild the Chelsea substation • Split the Hartford capacitor bank into two smaller capacitor banks • Install a +50/-25 MVAr SVC at Ascutney.	*Lead*: GMP Affected: All VT	$138M ($10M)	Out
Central Vermont • Rebuild Coolidge-Cold River 115 kV line.	*Lead*: GMP *Affected*: All VT	$172M ($7M)	Out

In the table above, the column labeled "Lead and affected distribution utility" refers to a formal process within the Vermont System Planning Committee for determining which utility leads planning and which utilities share the system and/or financial impacts for a given issue. The column labeled "Screened in or out of full NTA analysis" refers to the procedure used to determine whether a given reliability issue has any reasonable potential to be resolved with a non-transmission alternative, i.e., energy efficiency, demand response, or generation. The process used for this screening is described in detail, including links to the forms used to conduct project screening, at *http://www.vermontspc.com/about/key-documents#screening* .

[14] Project cost estimates include a 50 percent contingency (cost adder) to account for unknown factors that can affect project costs, which are based on year-of-expenditure dollars. The Central Vermont upgrade is estimated to cost $172M in 2028 dollars. Without the contingency and the cost escalation to 2028, the cost estimate is $75M. Costs associated with line additions also include substation expansion costs. Estimated Vermont share assumes most project elements are treated as PTF by ISO-NE, and that Vermont's share is 4 percent of the region.

LOCATION	**CONNECTICUT RIVER AREA**
Analysis	Coolidge to Ascutney overload and subsystem overloads. Low and high voltages, as well as voltage collapse in a subarea bordered by the Middlebury, Granite, Bellows Falls, and Webster 115 kV substations.
When deficiency occurs	Line overloads and voltage concerns for a single contingency that may remove one or more elements from service (N-1 conditions) and two succeeding contingencies (N-1-1.) The transmission overload is largely affected by power transfers from generation in Massachusetts and Vermont supplying New Hampshire load. The Vermont Yankee retirement has a positive impact on system performance.
Critical load level & timing of need[15]	**Coolidge-Ascutney capacity** Critical load level: 940 MW Year of need: 2021 **Coolidge-Ascutney asset condition** Critical load level: N/A Year of need: 2017 **Voltage concerns** Critical load level: 775 MW Year of need: In the past
Leading transmission solution	Rebuild 115 kV line and 46 kV lines, rebuild the Chelsea substation, split the Hartford capacitor bank into two smaller capacitor banks, install a +50/-25 MVAr SVC at Ascutney. Estimated cost: $138M. The Vermont share of this cost will be approximately $10M, assuming most of the project is classified as a pool transmission facility.
In service date	2017
Status	ISO-NE Needs Assessment and Solution Assessment have been completed. VELCO NTA screening analysis has been completed. ISO-NE has approved the proposed plan applications per section I.3.9 of the ISO-NE Tariff. VELCO is currently preparing documents for the section 248 filing.
Affected & lead utilities	**Lead utility:** GMP **Affected utilities:** All Vermont DUs

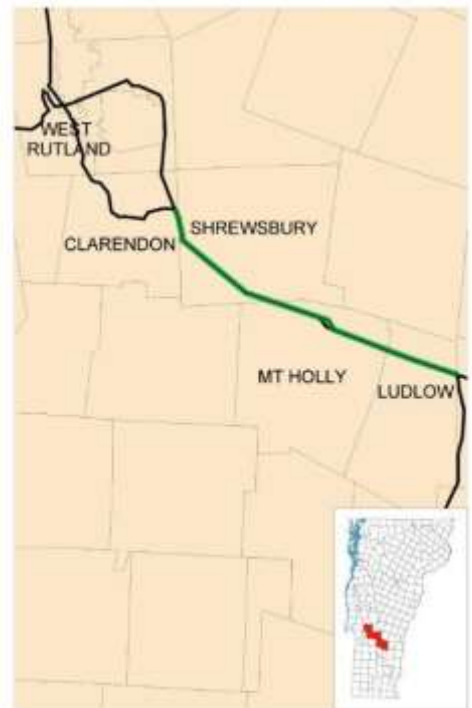
[15] The details of the critical load analysis can be found in the ISO-NE VTNH 2023 Needs Assessment report, which requires CEII clearance. That analysis assumes that up to 1200 MW of generation can be re-dispatched to reduce overloads. Any remaining concerns after the re-dispatch need to be resolved. That analysis also modeled some generators in service, despite these generators having announced their retirement in the near term. These generator retirements will be incorporated in the next 10-year studies that ISO-NE will conduct for the Vermont system. These retirements as well as several projects proposing to import power from Canada or New York could aggravate the line overloads and advance their need date.

NTA screening	**Question 1: Does the project meet one of the following criteria that define the term "impracticable[16]."** Answer: yes for some components. Justification below. • The K31 line and Chelsea substation upgrades address asset condition concerns as well as reliability concerns. • Splitting the Hartford cap bank addresses a high voltage concern (screens out because load reductions aggravate this concern and running generation for this purpose is wasteful and inconsistent with the economic operation of the grid). **Question 2: What is the proposed transmission project's need date?** • All components, except for the K31 reliability need, screen out based on the need date, which is preexisting. • The timing of the system reliability need for the K31 upgrade is 2021. • The timing of the condition need for the K31 upgrade is now. **Question 3: Could elimination or deferral of one or part of the upgrade be accomplished by a 25 percent or smaller load reduction or off-setting generation of the same magnitude?** • All components screen out based on the amount of load reduction or generation addition needed, as follows: – **To address the local voltage concerns** • 60 MW of load reduction is needed • Equivalent centralized generation solution of this size would cause system overloads • The Vermont portion of the load is 120 MW in the 2013 case • The load reduction would represent half of the existing load or two thirds taking into account the 20 MW load reduction already modeled • The 25 percent screening threshold is exceeded significantly – **To address the K31 overload concern** • 90 MW of generation addition at or east of Ascutney • Generation of this size would cause overloads • Would even need to be larger if installed elsewhere in VT • Load reduction of this amount did not resolve the concern • The 25 percent screening threshold is exceeded significantly **Question 4: Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $2,500,000?** • Not applicable—screened out in Q1, Q2 and Q3 above.
Equivalency	Not applicable. The NTA screening analysis showed that an NTA would not be a viable solution.

LOCATION	CENTRAL VERMONT AREA	

[16] Impracticable is defined as: (a) needed for redundant supply to radial load; (b) Maintenance-related, addressing asset condition, operations, or safety; (c) addressing transmission performance; (d) needed to address stability or short circuit problems; (e) other technical reasons why NTAs are impracticable (requiring a detailed justification reviewed by VSPC). NTA Screening Form as revised 9/272012.

Analysis	Coolidge to Cold River overload. No voltage concerns assuming the Connecticut River upgrades are completed.
When deficiency occurs	Line overloads when more than one element is out of service (N-1-1 condition).
Critical load level & timing of need	Critical load level: 1030 MW Year of need: 2028. Predicting loads below the critical need level until 2028.[17]
Leading transmission solution	Rebuild 115 kV line. Estimated cost: $172M (in 2028 dollars).
In service date	2028
Status	On hold. The need will be reevaluated as part of the next long-range plan in 2018.
Affected & lead utilities	**Lead utility:** GMP **Affected utilities:** All Vermont DUs
NTA screening	*Q 1: Does the project meet one of criteria that define the term "impracticable"?* A 1: No *Q 2: What is the proposed transmission project's need date?* A 2: 2028. Screens out due to timing being beyond ten years. *Q 3: Could elimination or deferral of all or part of the upgrade be accomplished by a 25 percent or smaller load reduction or off-setting generation of the same magnitude?* A 3: Not applicable. Screened out in Q2. *Q 4: Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $2,500,000?* A 4: Not applicable. Screened out in Q2.
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. An NTA 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 1030 MW after a transmission facility is out of service. An NTA solution would need to be located west and north of the North Rutland substation to be effective.



[17] New generation or an increase in imports of power through Vermont could hasten the need date for this project.

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. VELCO coordinates closely with local distribution utilities during the preparation of the plan to identify relevant issues and share information about study findings. In cases where information about a subsystem issue is not available to VELCO in time for a three-year update of the Plan, some reliability concerns may not be included in the plan. Additionally, distribution utilities make changes to their systems from time to time to better serve customers. These changes 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 subsystem may not be identified as part of the Plan.

Rutland Area (Blissville, North Rutland, Cold River)

Recent studies have identified a small reliability margin in the Rutland area at a Vermont load level of approximately 1000 MW. Load projections in the Rutland area follow a similar trend as the state load forecast; therefore, the Rutland area load is not anticipated to grow in the next ten years. Since the state load forecast is expected to remain around 1000 MW in the next 10 years, the Rutland reliability margin is also expected to be relatively constant during the ten-year period.

Following publication of the VSPC and public drafts of this plan, GMP filed its reliability plan for the Rutland area, as required by the processes established in Public Service Board Dockets 7081 and 7874. The GMP Rutland analysis shows that a transformer in West Rutland, estimated at $8M, can be avoided at the lower projected load levels by integrating GMP’s Florence 46 kV system into the greater GMP system, and utilizing various means to reduce and manage the Rutland area load, all at a cost of approximately $4 million. The detailed Rutland reliability plan may be viewed at http://www.vermontspc.com/gmp-rrp .

<table>
<tr><th>LOCATION</th><th colspan="2">NORTHERN AREA (HIGHGATE, JAY, NEWPORT, IRASBURG, BURTON HILL)</th></tr>
<tr><td>Analysis</td><td colspan="2">Low voltages in the northern subarea.</td></tr>
<tr><td>When deficiency occurs</td><td colspan="2">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.</td></tr>
<tr><td>Critical load level & timing of need</td><td>Critical load level

Year of need</td><td>Undetermined

Highly dependent on the status and amount of a single large customer’s load.
Load levels elsewhere in the northern part of the VEC system, such as the Jay ski resort, can also affect the timing.</td></tr>
<tr><td>Preferred transmission solution</td><td colspan="2">Addition of 46 kV capacitor banks. Upgrade of the Moshers Tap. These upgrades will be completed in stages as the load continues to grow.
Estimated costs:
Burton Hill 46 kV capacitor banks — $3M
Moshers Tap upgrade — $22M ($900,000 VT share of PTF)</td></tr>
<tr><td>In service date</td><td colspan="2">Unknown at this time.</td></tr>
<tr><td>Status</td><td colspan="2">Analyses continue to be performed to take into account any changes in load predictions and other factors.</td></tr>
<tr><td>Affected & lead utilities</td><td colspan="2">Lead utility: VEC
Affected utilities: VEC, Barton, and Orleans</td></tr>
<tr><td>NTA screening</td><td colspan="2">Q 1: Does the project meet one of criteria that define the term “impracticable”?
A 1: No.
Q 2: What is the proposed transmission project’s need date?
A 2: TBD. Depends on the status of the relevant customer’s load.
Q 3: Could elimination or deferral of all or part of the upgrade be accomplished by a 25 percent or smaller load reduction or off-setting generation of the same magnitude?
A 3: TBD. Depends on the status of the relevant customer’s load.
Q 4: Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $2,500,000?
A 4: TBD.</td></tr>
<tr><td>Equivalency</td><td colspan="2">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 near the Irasburg substation.</td></tr>
</table>

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. If the affected distribution utilities determine that these issues require resolution, these projects would involve grid elements owned by distribution utilities.

VELCO's 2015 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 and a more granular focus specifically on subsystem performance 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, a utility may accept the impacts of an infrequent power outage rather than to invest in infrastructure to eliminate the power outage risk based on its analysis or costs, benefits and 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 2015 in this table)**	**90/10 Load Forecast for Year (MW)**	**Contingency**	**Reliability Concern**	**N-1 Criteria Violation**	**Affected DUs**	**Lead DU**
Hartford	2015	<1030	Sub-transmission	Thermal	Ryegate – Wells River – Woodsville	GMP	GMP
Hartford	2015	<1030	Sub-transmission	Low voltage	Ryegate – Hartford	GMP	GMP
Chelsea	2015	<1030	Transmission	Low Voltage	Chelsea area	GMP	GMP
Chelsea / Hartford	2015	<1030	Transmission	Voltage collapse	Chelsea and Hartford areas	GMP	GMP
Ascutney	2015	<1030	Sub-transmission	Low Voltage	Lafayette – Bellows Falls	GMP / PSNH	GMP
Ascutney	2015	<1030	Sub-transmission	Thermal	Bellows Falls – Vilas2	GMP / PSNH	GMP
Ascutney	2015	<1030	Transformer Sub-transmission	Thermal	Ascutney - Highbridge – Lafayette	GMP / PSNH	GMP
Ascutney	2015	<1030	Transformer Sub-transmission	Thermal	Lafayette – Maple Ave – Claremont – Joy	GMP / PSNH	GMP
Blissville	2015	<1030	Transformer	Low Voltage	Blissville area	GMP	GMP
Blissville	2015	<1030	Transformer	Thermal	North Rutland – West Rutland	GMP	GMP
Blissville	2015	<1030	Transformer	Thermal	West Rutland - Castleton - Hydeville - Blissville	GMP	GMP
Rutland	2015	<1030	Transformer	Thermal	North Rutland	GMP	GMP
Rutland	2015	<1030	Transformer	Thermal	West Rutland - Proctor - Florence	GMP	GMP
Montpelier	2015	<1030	Sub-transmission	Low Voltage	Ryegate / Newbury	GMP	GMP
Montpelier	2015	<1030	Transformer Sub-transmission	Thermal	Berlin - Mountain View Tap	GMP	GMP
Montpelier	2015	<1030	Sub-transmission	Voltage collapse	South End / Websterville / Legare	GMP	GMP
Montpelier	2015	<1030	Sub-transmission	Thermal	Legare – Mt Knox – Websterville	GMP	GMP
Montpelier	2015	<1030	Sub-transmission	Low Voltage	Moretown – Irasville - Madbush	GMP / WEC	GMP
Montpelier	2015	<1030	Sub-transmission	Thermal	Montpelier – W Berlin – Northfield	GMP / WEC	GMP
Burlington	2015	<1030	Transformer Sub-transmission	Thermal	Gorge – McNeil	GMP / BED	GMP
Newport	2015	<1030	Transformer	Low Voltage *	Irasburg – Portland Pipe	VEC / Barton / Orleans	VEC
Newport	2015	<1030	Transmission	Voltage Collapse *	Newport area	VEC / Barton / Orleans / WEC / GMP	VEC
St Johnsbury	2015	<1030	Sub-transmission	Low Voltage	Comerford – Bay Street	GMP	GMP
St Johnsbury	2015	<1030	Sub-transmission	Thermal	Comerford – Gilman	GMP	GMP

* No concerns were identified with the Itron winter load forecast; however, low voltages and voltage collapse can occur with higher winter load levels in the Newport load zone, particularly at a large customer's site, which is currently inactive, but may reconnect the load.

Public input on the 2015 plan update

VELCO conducted an extensive public engagement process to meet the requirements of 30 V.S.A. 218c and to actively solicit input on the 2015 Vermont Long-Range Transmission Plan—Public Review Draft. Opportunities for public 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. Prior to the Public Review Draft, the VSPC reviewed and provided input to a VSPC draft through the process established in Docket 7081.

In March, VELCO announced two public forums on the draft plan: in Rutland April 8 and in Montpelier April 15. The forums were promoted with an email invitation, followed by a postcard mailing sent to over 1000 contacts. VELCO also advertised the public forums with 59 display ad days in the *Addison Independent, Bennington Banner, Burlington Free Press, Brattleboro Reformer, Caledonia Record, St. Albans Messenger, Rutland Herald, Stowe Reporter, Times Argus,* and *Valley News*. These and other media also received media releases. In addition to the two public forums, VELCO offered to attend and make a presentation of the draft plan to each of the 12 regional planning commissions (RPC). Two RPCs requested and received presentations and some additional presentations may be scheduled this summer.

As required by law, VELCO created a verbatim record of the public questions and comments from the public forums. The transcribed comments are available at http://www.velco.com/2015PlanInput .

Total attendance at the VELCO-organized public forums was 28. While the quality of the exchange was high, it continues to be our experience that transmission planning issues do not draw substantial interest on their own unless a project has the potential to affect stakeholders' communities. In the case of the current plan, no transmission project falls within the 10-year horizon except the Connecticut River Valley Project, for which we were already conducting extensive community-specific public outreach at the time of the plan-related public engagement effort.

The vast majority of discussion at the public forums consisted of questions from the audience and responses from VELCO. All issues raised at the forum were either already covered within the body of the plan or fall outside its scope.[18] The following list reflects the areas of interest discussed in the public forums and comments. Specific questions and responses can be viewed in the transcript linked above.

- The cost recovery mechanism for VELCO and Vermont utilities and how cost recovery relates to power supply and generators.
- Many questions regarding proposed merchant transmission.
  - The power sources, purpose and impacts of proposed merchant transmission projects.
  - The mechanism by which merchant developers recover costs and receive revenue.
  - Participants expressed the opinion that any cost impacts from the effects merchant transmission has on the reliability of the existing transmission system should be taken into account in permitting the merchant projects.

[18] For issues beyond the scope of the plan, we urge readers to consult the Vermont Comprehensive Energy Plan, for which a public engagement process associated with a 2015 update was underway at the time of publication. The 2011 CEP, as well as the 2015 update process, can be accessed at http://www.vtenergyplan.vermont.gov/

- Interest in whether merchant transmission would displace coal and oil.
- Questions regarding whether any proposed merchant transmission could obviate the need for an identified reliability project.

- One participant questioned costs associated with the synchronous condenser at Kingdom Community Wind. He stated that ratepayers expect the need for such equipment to be identified at the outset of the planning and permitting process. GMP and VELCO representatives described some of the complexities associated with the study process in this particular case.
- A participant described work he had done to develop options for the use of geothermal energy in Vermont. He urged utilities to consider the value of geothermal generation.
- Participants asked a number of questions about the current impacts of solar generation in the state.
  - The amount of power being derived from solar installations.
  - How VELCO balances its system when significant intermittent generation is flowing onto the grid or offsetting load.
  - Impacts of solar on peak load.
- Participants asked a number of questions about the load forecast.
  - Difference between the ISO-NE and VELCO forecasts.
  - Projected impacts of electric vehicles.
- Several people were interested in understanding the impacts of FERC Order 1000 on Vermont and the region.
- One participant sought assurance that renewable energy would serve Vermont's energy needs in the long run. He expressed concern that, as the amount of distributed generation grows, Vermont's grid must adapt to avoid a loss of reliability.

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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

load—see ***demand***.

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

net metering—An electric policy that allows consumers who own small sources of power, such as wind and solar, to get credit for some or all of the electricity they generate through the use of a meter that can record flow in both directions. The program is established under Title 30 Vermont Statutes section 219a.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Abbreviations

AC	Alternating current
DC	Direct current
DG	Distributed generation
FERC	Federal Energy Regulatory Commission
FCM	Forward Capacity Market
GMP	Green Mountain Power
HQ	Hydro Québec
HVDC	High voltage direct current
ISO-NE	ISO New England
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
PSD	Vermont Public Service Department
PSNH	Public Service of New Hampshire
PV	Photovoltaic generation (solar)
SPEED	Sustainably Priced Energy Enterprise Development
VEC	Vermont Electric Cooperative
VEIC	Vermont Energy Investment Corporation
VELCO	Vermont Electric Power Company
VJO	Highgate Vermont Joint Owners
VY	Vermont Yankee
VSPC	Vermont System Planning Committee