

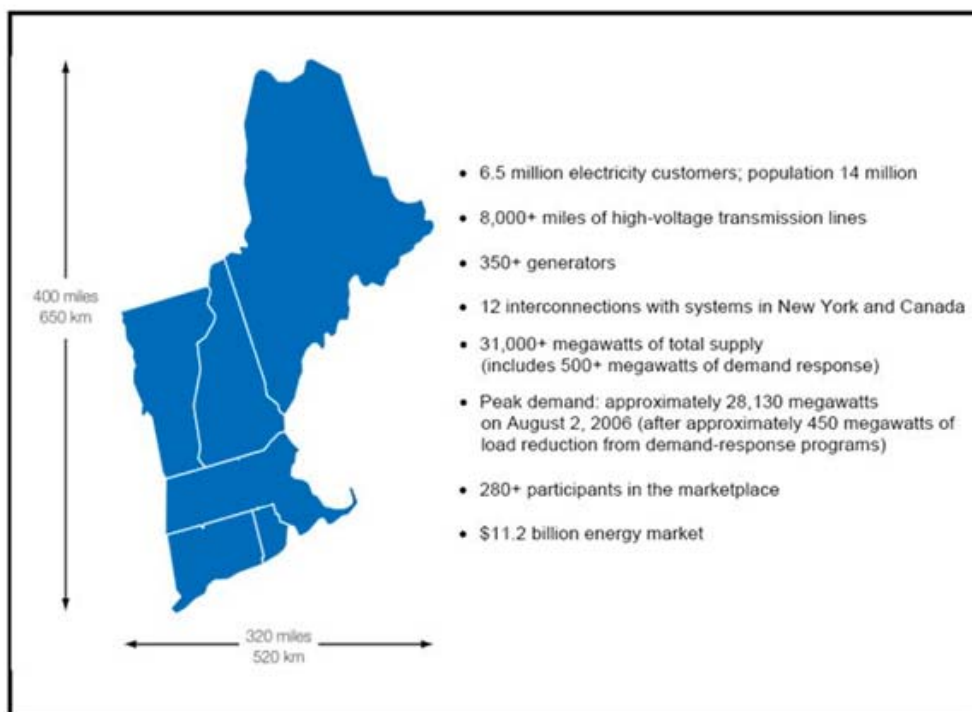
2 The Transmission Planning Process

2.1 New England Transmission System and Operations

Power systems have been called the most complex machines in the world because the electricity being made by power plants and delivered via the transmission and **distribution** wires must be in perfect balance with the electricity demanded by all customers at all times. Vermont’s transmission system is interconnected with other utility transmission systems across New England, Canada and New York, which requires close coordination with these other states and regions to ensure electricity is provided reliably and at an affordable cost.

ISO New England Inc. (ISO-NE) is an independent, non-profit organization that plans and operates New England’s bulk electric system, administers the wholesale electricity markets and oversees regional system planning. ISO-NE ensures individual utility companies plan for and operate the New England transmission system, or transmission “grid,” in a way that assures the reliability of the entire New England system.

Figure 2-1. Key facts about New England electricity (source: ISO-NE).



Note: “participants” include power generation owners, marketers, transmission owners, and other parties.

ISO-NE reviews and decides to approve or not approve upgrades, modifications, and additions to the New England transmission system, including Vermont. If a transmission project is deemed to provide reliability or economic benefit to New England, ISO-NE will categorize the project as a Regional Benefit Upgrade and the cost of that project will be shared throughout the New England states using a funding mechanism called **Pool Transmission Facilities (PTF)** funding. Most of the transmission reinforcement needs discussed in this plan would likely be deemed by ISO-NE as benefitting all of New England. Vermont's share of any regionally funded transmission project, whether in or out of state, is approximately four percent of the cost, which reflects Vermont's percent share of New England electric load.

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

The planning process discussed in this report is focused specifically and exclusively on the identification of issues and possible solutions to meet reliability standards. Transmission projects designed to meet other needs around New England, such as bringing renewable or low-cost power to customers, are under discussion around the region but will follow a different process.

Generally electric utilities interconnect within logical geographic regions, also called "power pools," that are sufficiently large to achieve reliability and economy-of-scale benefits. Although these power pools have ties with neighboring regions' power pools, they often directly generate most of the electricity consumed within their region. While this is the case for New England as a whole, for Vermont, these interconnections are even more critical. On a peak demand day in summer, Vermont may import between 75 percent and 90 percent of its electric demand via its transmission tie-lines with Vermont Yankee and Highgate, Canada, and the rest of New England —sources located at the edges or outside of Vermont. Vermont is therefore *highly* dependent upon the transmission network.

2.2 Key Transmission Planning and Operating Criteria

The 2003 **blackout** affecting 50 million people in the US and Canada led to more stringent requirements for transmission planning. The Federal Energy Policy Act of 2005 (the "Act") sought to prevent future large-scale blackouts and other electric reliability issues by making national reliability standards mandatory. Since June 4, 2007, users, owners and operators of transmission systems within the 48 contiguous states can be severely penalized for failing to comply with 83 electric reliability standards approved by the U.S. Federal Energy Regulatory Commission (FERC). Violation of any of the 83 standards is potentially subject to a penalty of up to \$1 million per day.

If the transmission system fails, then large regions of the power system can experience a blackout. Achieving a high degree of reliability requires the system to have redundant features and excess

capacity so that there is flexibility to reroute power due to equipment failures or when weather, accidents or other catastrophes cause a problem on the system.

Three out of the 83 national standards are particularly significant to planning for transmission system reliability. The first standard requires analyzing the transmission system using a scenario, called “N minus zero” (**N-0**) where “N” represents normal operating conditions for a given set of system components. Electric systems contain thousands of pieces of critical equipment, such as **transformers**, that will occasionally fail. To provide another layer of protection, utility planners must look at adding system backup, or robustness, to cover a second scenario called a “single **contingency** situation” such as the failure of a transformer or a lightning strike that causes the outage of a transmission line. These so-called single contingency scenarios are known as “**N-1**” (N minus one) conditions. The general philosophy is that no single failure of a piece of equipment connected to or comprising the transmission network should cause a large number of customers to lose power. Transmission designers further test the system design by looking at scenarios involving two or more equipment failures (known as “N minus one minus one” scenarios or “**N-1-1**”).² To recognize the specific regional attributes of its transmission grid, ISO-NE has additional planning standards. For example, the system must be designed so that it can handle electric demand under extreme weather conditions (the so-called “**90/10 load**”), the outage of the two most critical generators, and limitations on the use of fossil fuel-fired peaking generation units. A detailed report of the exact modeling parameters used to create the transmission reinforcement plan is contained in [VELCO’s technical analysis](#).

By using these and other criteria to plan and design the generation and transmission system, transmission utilities seek to ensure that customers rarely lose power because of a problem in these parts of the system. Most customer outages are caused by a local problem on the distribution system such as a tree coming in contact with an overhead wire.

2.3 Electric Demand and Transmission Planning

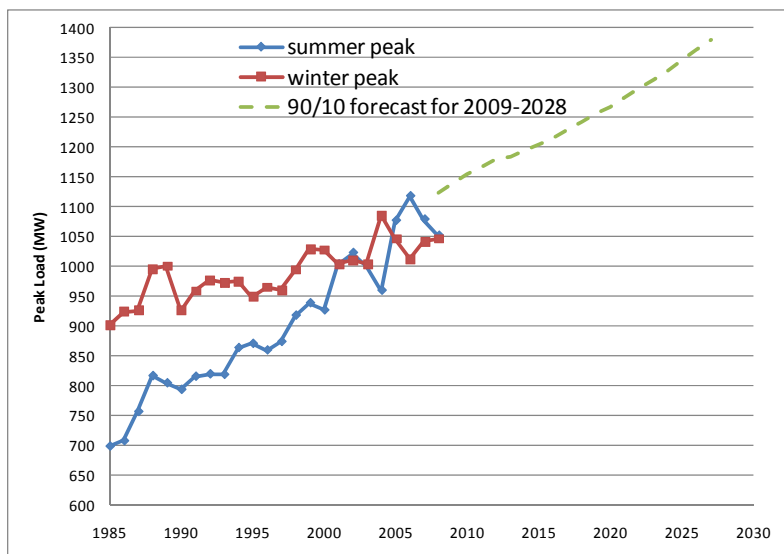
In years past, Vermont had its highest electrical demands in the winter. Those demands reached over 1000 **megawatts (MW)** in 1989. Actions taken by Vermont’s regulators, utilities and customers resulted in a significant reduction of winter peak electric demand growth from the late 1980s to the present day. During the same period, steady peak demand growth occurred in the summer. In 1988, during a hot, humid summer, Vermont peak demand was 815 MW or barely 80 percent of the winter peak. By 2006, the summer peak demand had risen to 1118 MW, surpassing the winter peaks and driven in part by an increase use of air conditioning over that time. The relatively mild summer in 2007 caused the winter and summer peak loads to almost equal. The overall trend has been one of increasing peak electric demand. From 1991 to 2006, the non-weather adjusted annualized electric peak demand growth averaged 1.2 percent per year. Meanwhile, summer peak demand growth from 1991 to 2006 averaged

² The “N-0,” “N-1,” and “N-1-1” scenarios are defined by national transmission planning standards [TPL-001](#), [TPL-002](#), and [TPL-003](#), North American Electric Reliability Corporation, www.nerc.com.

almost 2.2 percent per year. New transmission requirements are driven in part by the need to reliably serve this growing electric demand.

For transmission planning purposes, planners examine a range of forecasts. Vermont’s analysis uses a forecast with a 90 percent probability (nine out of ten chance) that the actual peak demand will be at or lower than the forecast. The so-called “90/10” forecast is used to ensure the transmission system is built to handle even low probability, but realistic, scenarios. For Vermont, the “90/10” forecast averages to about a 1.1 percent per year increase in summer peak demand. In 2018 and 2028, the planning load levels are 1275 and 1425 MW respectively.

Figure 2-2. Vermont peak demand - actual from 1985 to 2008, and forecast through the 2028 planning horizon.



Source: Historical data from VELCO. 2009-2028 forecast is based on analysis from ITRON (an independent consulting firm) and represents a 90/10 forecast (90 percent chance the actual peak will be at or below the forecasted peak).

The way power flows within Vermont is not only impacted by the electric demand inside of Vermont but also across New England, Canada, and other states. The New England load-level for year 2018 was modeled at 33,200 MW, which also represents an estimated extreme weather 90/10 load and is based on the [2008 Capacity, Energy, Load, Transmission \(CELT\) Report](#) issued by ISO-NE.

Developing a projection of future electric demands is a complex analysis. Historical usage, customer data, economic projections, appliance studies, and efficiency measures are just some of the factors analysts examine when developing forecasts. The load forecast used for transmission planning purposes includes the effects of expected changes to energy efficiency due to new regulations, such as the increased use of compact fluorescent lighting in the near future. The load forecast also incorporates the effects of ongoing **demand side management (DSM)** efforts because the historical data include the effects of past DSM. However, the effects of additional DSM due to increasing budgets for energy efficiency were not included in the load forecast. The load forecast also does not take into account

recent macroeconomic events, such as the current economic downturn, however the record of historical load data shows that prior recessions have had limited impact on long-term load growth.

Efficiency Vermont is the entity responsible for most energy efficiency, or DSM, programs in the state. They are currently preparing the first 20-year DSM forecast, which will be ready later in 2009 and will help inform future load forecasts. Any additional DSM efforts projected by that forecast can be accounted for by making a simple subtraction of the DSM impact from the load forecast.

Because of these and other uncertainties associated with forecasting electric demand, the need for transmission reinforcements is stated not only in terms of the year that each is estimated to be needed, but also by the level of electric demand in Vermont where a solution becomes necessary. The load level provides a triggering threshold, though the year in which it is reached may change from the predicted “year of need.”

2.4 Vermont’s Transmission Planning and Docket 7081 Process

VELCO is required to publish a Long-Range Transmission Plan that looks out 20 years and is updated every three years. That Plan analyzes the transmission system and serves as the foundation for a process that considers where transmission upgrades are needed and where alternatives can be employed. The intent of system planning is to assess the transmission system’s needs over time as things such as peak load levels and generation resources change. In addition VELCO must comply with the previously mentioned planning requirements of ISO-NE and federal agencies such as the FERC.

The last plan was produced in 2006 and this plan must be finalized by July 1, 2009, following public input on this draft. The transmission planning process and planning criteria have undergone substantial changes since 2006. These modifications include the mandatory national standards discussed above. In 2007 Vermont’s Public Service Board (PSB) approved a new, collaboratively designed process that is defined in a Memorandum of Understanding (MOU) in [Docket 7081](#). The process is designed to facilitate full, fair and timely consideration of non-transmission alternatives to new transmission projects where such alternatives are cost-effective and meet design and reliability criteria. It accomplishes this goal through the Vermont System Planning Committee, which increases collaboration among utilities, increases transparency of the process, and involves the public in decisions about alternatives. In addition the new process extends the planning horizon from 10 to 20 years, which provides time to fully consider all alternatives.

The Docket 7081 MOU made major changes to Vermont’s transmission planning process including:

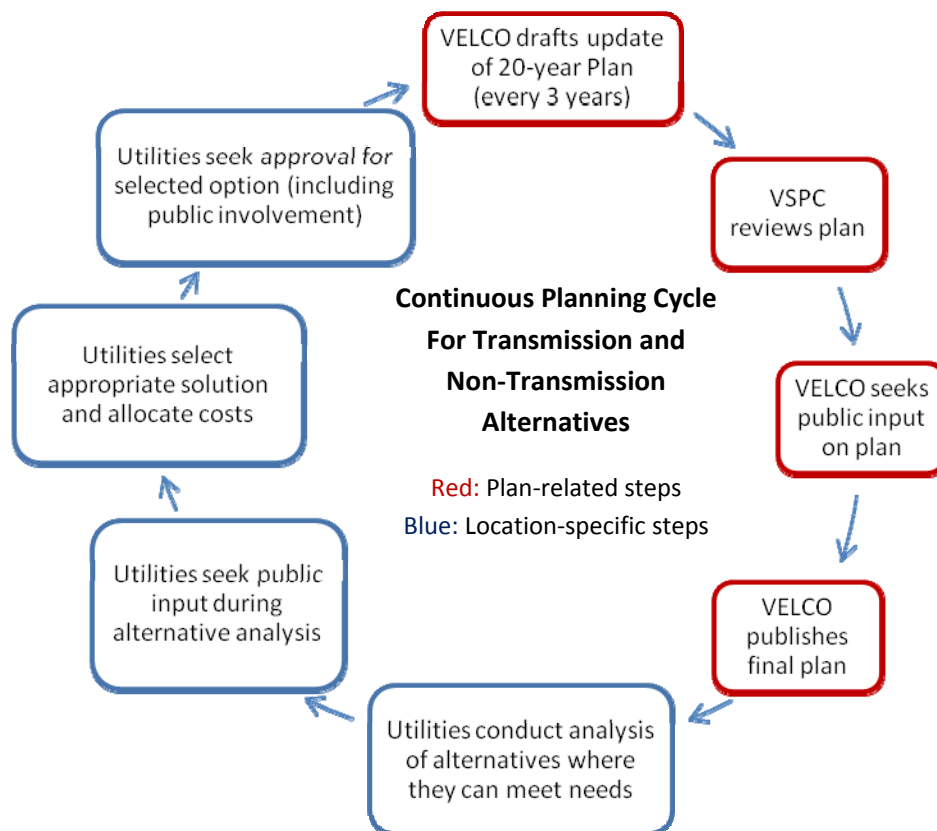
- **Creating the Vermont System Planning Committee (VSPC).** The members of the VSPC include: representatives of each Vermont electric distribution and transmission utility; and three public members who are appointed by the PSB to represent residential consumers, commercial and industrial consumers, and environmental protection advocates. In addition, three non-voting members participate in the VSPC, including the DPS, EEU, and the entity appointed to foster the development of renewable energy contracts, called the Sustainably Priced Energy Enterprise

Development Facilitator (SPEED Facilitator). The VSPC meets quarterly to review utilities' analyses, planning and cost allocation proposals to address transmission system reliability deficiencies by local distribution utilities and VELCO. For more information visit www.vermontspc.com.

- **Increasing the planning horizon from 10 years to 20 years.** While state legislation mandates a 10-year planning horizon it was recognized that a longer-term horizon of 20 years is of value. It can take as long as 10 years to plan, approve, permit, and construct a major transmission project. By expanding the planning horizon, the potential need for projects far into the future can be anticipated. Additionally, Non-Transmission Alternatives (NTAs), such as energy efficiency or local generation, can be considered to avoid or defer the need for transmission reinforcements.
- **Identifying subtransmission system issues.** Potential inadequacies in Vermont's 34,000 to 70,000 volt systems are to be identified, but solutions to subtransmission issues will be the responsibility of local distribution utilities and, therefore, the transmission solutions are not proposed in this analysis.
- **Formalizing the process of considering alternatives.** A formal and standard process is defined for evaluating whether alternatives to building transmission can solve each identified reliability deficiency. The process includes an "open door" for developers of potential alternatives to contact affected utilities and regulators to discuss possible NTAs. The process also includes a "market test," typically involving a solicitation for proposals to identify potential alternatives.
- **Assigning clear roles and steps.** Responsibility for moving the steps in the process forward is clearly assigned to lead and **affected utilities**, who are identified through a formal process. Affected utilities are those whose systems cause, contribute to or would experience an impact from a reliability issue. The **lead distribution utility** is the utility selected by the affected utilities to facilitate decision-making and to lead the effort to conduct the analysis of alternative solutions.
- **Expanding public involvement in the planning process.** All VSPC meetings are open to the public and at least two public meetings are held in proximity to possible transmission solutions. In addition, the process includes requirements for a robust approach to public outreach in the development of plan updates and as specific solutions are developed to each reliability issue.

An overview of Vermont's transmission planning process is provided in Figure 2-3. The process is currently in the "VELCO seeks public input" step on the draft plan, and will include multiple public meetings and opportunities for other forms of input.

Figure 2-3. Overview of Vermont’s transmission planning process.



This outreach process will provide an opportunity for towns and regions to understand and provide input to the future of the electric system in their areas.

After the public outreach process and filing of the final 2009 plan and its underlying technical analysis, the VSPC process will proceed to its next step for each individual transmission performance issue. These next steps are complex and may take years to complete. The 2009 Plan includes a preliminary screening of each reliability deficiency to determine whether it passes a [three-part test](#) that has been approved by the Public Service Board for this purpose. The screening makes a determination of whether alternatives to building transmission could be viable in each case. The screening is intended to include as many projects as possible, which, if they “screen in,” move on to a full analysis of possible alternatives. The full non-transmission alternatives analysis then is the responsibility of the affected utility, guided by the lead utility.

For those projects that “screen out,” and for those that are fully analyzed and it is determined that a transmission upgrade is the best alternative, the responsible companies – VELCO and/or one or more of the local utilities – will do the detailed planning for building the transmission upgrade. During this planning, the companies make extensive contact with local communities where the project will be built to provide information and gather input about how best to meet transmission system needs while recognizing local concerns.

Once transmission project planning is completed, the responsible companies file an application (called a “petition”) with the Vermont Public Service Board (PSB) seeking approval to construct the project. Proposed projects must also be approved by ISO-NE, which generally looks at projects to ensure they will not do harm to other utilities in the region.

The Vermont approval process is referred to as the “Section 248 process” for the section of Title 30, Vermont Statutes, which lays out the requirements. The Board is essentially a court, and the process for considering the petition is a formal one. During the process, the Department of Public Service acts as the public’s advocate before the Board, and other individuals and groups may formally “intervene.” If and when the Board grants approval, in the form of a Certificate of Public Good, the responsible company can begin construction, once it has all other required permits and approvals. The PSB publishes a [Citizens’ Guide to the Section 248 Process](#), which provides a detailed description of the formal process.

The process from identification of the problem to implementation of a solution typically takes three to five years. During that time, the public will have at least three opportunities to provide input. As noted above, the first opportunity, in April and May 2009, is focused on this plan. A second opportunity occurs when utilities are evaluating alternatives to building transmission to solve a particular reliability problem. Finally, when and if utilities are seeking PSB approval to implement a project, they will involve the public prior to making a formal request and the PSB will conduct local hearings in each affected country during its deliberation.

All of these activities are undertaken in parallel with VELCO’s responsibility to meet reliability criteria established on a nation-wide basis by entities such as the [North American Electric Reliability Corporation](#), or regionally by groups such as the [Northeast Power Coordinating Council](#) and ISO-NE. ISO-NE has the responsibility for planning the interconnected transmission system in New England. Each year ISO-NE examines system needs and publishes a [Regional System Plan](#) which describes the collective transmission needs of the region in one document. VELCO assists ISO-NE by including Vermont’s transmission needs in this document. This report and others comprise the necessary documentation that ISO-NE and VELCO use to show planning compliance with current and forecasted system needs.