VERMONT SYSTEM PLANNING COMMITTEE

Draft Meeting Minutes
July 16, 2025
Rutland, Vermont

The Vermont System Planning Committee held a quarterly meeting on July 16, 2025. Shana Louiselle, VSPC facilitator, called the meeting to order at 9:30 a.m. Ms. Louiselle reviewed the agenda for the meeting.

Ms. Louiselle asked if there were any corrections or objections to the January meeting minutes and not hearing any the minutes were approved without objection.

Introductions

A list of attendees by sector appears at the end of these minutes.

Geographic Targeting Subcommittee Report

Shana Louiselle reported that the Geographic Targeting (GT) Subcommittee met in July to review Vermont utilities' upcoming capital projects. Washington Electric Cooperative presented plans to rebuild the Jackson Corners and Mount Knox substations to address load growth, aging infrastructure, and increasing distributed generation. Members requested more detailed data before ruling out non-transmission alternatives (NTAs). VELCO presented its East Fairfax substation upgrade that screened out as an asset maintenance project, and members asked for clarifications design choices before finalizing the review. Both items will return for further discussion in the fall, ahead of the October deadline for geographic targeting recommendations to the Public Utility Commission (PUC).

Forecasting Subcommittee Report

Zakia El Omari reported that the Forecasting Subcommittee met in June to review the load forecast plan being developed by Itron in support of the 2027 Vermont Long-Range Transmission Plan (LRTP). Itron outlined a four-phase approach: (1) data gathering of system- and zone-level loads, including solar generation; (2) forecasting for new technologies such as EVs, heat pumps, solar, and battery storage; (3) establishing a baseline load forecast independent of new technologies; and (4) scenario development accounting for high/low technology adoption, EV charging behaviors, storage, extreme weather, and economic growth. The forecast report and dataset are scheduled for delivery by April 2026.

The methodology incorporates Vermont-specific economic indicators, weather trends, energy efficiency standards, sectoral energy use, and adjustments for distributed solar. EV demand management and battery storage behavior are included for the first time. Distribution-level forecasting was discussed as a potential enhancement. Itron will invite another client to present their experience with distribution-level forecasting at the fall subcommittee meeting.

Flexible Load Management Working Group Report

Philip Picotte, Utilities Economic Analyst at the Vermont Public Service Department (PSD), reported that the working group's work is nearing completion, with final recommendations expected in October. The group is documenting the current roles and responsibilities, with two meetings held over the past quarter to review the status quo. Efficiency Vermont has provided a summary of its FLM activities, including direct support to distribution utilities (DUs) and broader supply chain engagement. A corresponding list of DU actions and needs is being developed to clarify the DU–Efficiency Vermont relationship. Responses from DUs confirming the status quo and outlining desired future roles are expected next week. The group will review these responses in an early August meeting and integrate them into a final report addressing all three objectives.

Coordinating Subcommittee

Ms. Louiselle reminded the Committee that the next VSPC quarterly meeting is on October 29, 2025 at the Killington Grand Hotel in Killington, VT.

NERC Interregional Transmission Planning Study

John Moura from NERC presented on the recent Interregional Transfer Capability Study (ITCS) and the broader challenges facing the electric grid. He explained that, historically, utilities had years to prepare for large new loads such as industrial facilities, but today's demand growth – driven by data centers, electrification, and EV adoption – can emerge in a matter of months. This creates a mismatch between the speed of new demand and the long lead times needed for transmission and generation development, forcing planners to rethink traditional approaches.

A central theme was the changing resource mix and its impact on system adequacy. Retirements of coal, oil, and older natural gas plants are removing large amounts of dispatchable generation that provided essential reliability services. While wind and solar are being added at record levels, they do not provide the same reliability attributes, and their reliance on inverter-based technologies creates new technical challenges. Ensuring voltage stability, frequency response, and system recovery after disturbances is becoming more complex. This is compounded by the fact that demand centers and new renewable generation resources are often geographically distant, requiring stronger interregional transmission connections.

Transmission was highlighted as a critical tool for balancing the grid, but not a complete solution. Neighboring systems cannot always be relied upon to provide power if they, too, are facing shortfalls. Mr. Moura noted a combination of interregional coordination, new generation resources, and demand-side solutions will be needed. The ITCS, mandated by Congress, found that an additional 35 GW of transfer capability would be needed nationally to manage extreme weather events. Even so, the study concluded that transmission expansion alone would not fully close resource adequacy gaps—particularly in areas reliant on imports from Canada, such as Quebec, where expected resource development is projected to reduce available export capacity.

The presentation also underscored the shifting risk profile of the grid. Whereas summer peak demand was once the dominant concern, planners must now prepare for risks across all seasons and times of day. Evening "net peaks" after solar output drops, winter heating loads, and extreme weather events such as Winter Storm Elliott are straining system resilience. Prolonged lulls in wind and solar output, known as "Dunkelflaute," were cited as another growing challenge. These events highlight the need for adequacy planning that considers 24/7 energy availability, not just peak-hour capacity.

Finally, Mr. Moura noted the unprecedented demand growth from data centers, cryptocurrency operations, and electrification. Many speculative siting requests create “phantom load,” complicating demand forecasts. He emphasized that demand flexibility will play an increasingly important role. If large loads can adjust consumption in response to system needs, they could provide significant reliability benefits. Overall, Mr. Moura highlighted that reliability planning must evolve beyond a narrow peak-capacity lens to ensure energy adequacy, resilience, and coordination across regions.

Northeast Collaborative on Interregional Transmission Planning

Johannes Pfeifenberger from Brattle Group presented the Northeast Collaborative Action Plan and the interregional transmission analysis that informed it. Mr. Pfeifenberger emphasized that multiple national and regional studies – nine in total – have reached consistent conclusions: expanding interregional transmission delivers significant reliability, economic, and resource adequacy benefits. While study assumptions and outcomes differ, the common bottom line is that investment in interregional lines allows regions to spend money now in order to save later. For example, the 2024 National Transmission Planning Study found that doubling to quadrupling U.S. transmission capacity by 2050 could reduce system costs by up to $1 trillion, with every dollar invested yielding $160–180 in benefits. These benefits come from sharing reserves, reducing the need for redundant generation, enabling power trading between regions, and avoiding smaller, piecemeal upgrades. Despite the clear value proposition, existing planning processes are largely reliability-driven and siloed within regions, leaving little space to advance interregional projects or to plan for uncertainty tied to extreme events, load growth, or evolving technologies.

Looking specifically at the Northeast, the analysis identified “low-regrets” interregional expansions, including 2 GW of added transfer capability between New York and PJM, 1.7 GW between New York and New England, and up to 10 GW between Canada and the Northeast by 2035. These additions would improve cost-effectiveness, support clean energy integration, and enhance resilience during weather-driven events. Trading opportunities across borders were also highlighted, with New England–Quebec and New York–Quebec exchanges offering value. Massachusetts’ 2050 decarbonization study and MIT’s long-term analysis both reinforced that future needs will be even larger, suggesting that investments in the next decade should be designed with long-term scalability in mind.

Mr. Pfeifenberger then reviewed the Northeast States Collaborative Action Plan, published in April 2025 by six states, which outlines near- and mid-term steps to overcome gaps in planning and project development. Near-term actions include issuing a request for information (already underway) to identify shovel-ready interregional projects, developing a flexible cost allocation framework, addressing barriers to HVDC deployment in the Northeast, aligning offshore wind and transmission procurement, improving interregional coordination under FERC Order 1920, and optimizing use of existing ties—an area where inefficiencies are estimated to cost $3 billion annually. Mid-term actions envision coordination with RTOs on tariff revisions, exploring pooled procurement of constrained transmission equipment, and addressing contractual pathways to evolve generator tie lines into shared, networked transmission.

Finally, the discussion touched on the broader need for improved planning processes that account for uncertainty, integrate economic and policy drivers alongside reliability, and adopt “least-regrets” strategies—such as building flexible infrastructure that can scale over time. Examples from MISO, SPP, California, Europe, and Australia demonstrate that more effective interconnection processes and planning tools exist and could be applied in the Northeast. Notably, fast-track processes in other regions allow new resources to interconnect within 6–12 months, compared to the multi-year delays common today. Mr. Pfeifenberger noted that while the scale of investment needed is large, coordinated interregional planning, efficient use of existing infrastructure, and forward-looking procurement could unlock significant system-wide savings and reliability gains.

State Perspective on interregional ties to Vermont

Lou Cecere with the Vermont Department of Public Service highlighted Vermont's strategic position at the intersection of multiple balancing authorities, noting the state's potential to support regional transmission development despite limited internal generation resources. Opportunities such as offshore wind and small modular reactors could play a role in the future, while Vermont continues to explore cross-border partnerships, including with Hydro-Québec, to support resource adequacy. Mr. Cecere emphasized the importance of pursuing cost-effective, low-regrets transmission and generation projects, prioritizing affordability and prudent investment in existing assets. The state is also considering issuing an RFI to guide long-term resource planning, informed by upcoming ISO New England analyses. Vermont's work evaluating non-transmission alternatives was highlighted as a valuable contribution to regional efforts to manage costs and support decarbonization goals.

ISO-New England Update

Sarah Adams, Senior State Policy Advisor for Vermont at ISO New England, joined by Carrie Schliftinger, the State Policy Advisor for Connecticut and Rhode Island provided a regional update. Key resources highlighted include the annual Consumer Liaison Group report, state and regional grid profiles, and a Planning Advisory Committee forum on grid-enhancing technologies. Adams also noted the upcoming retirement of ISO CEO Gordon Van Wiele in January 2026, with Vahmsi Chadalavada, Chief Operating Officer, selected as his successor.

Market updates show May 2025 wholesale electricity prices averaged $33 per megawatt-hour, with peak demand around 15,000 MW. Generation was primarily from natural gas and nuclear, with renewables and hydro contributing smaller shares. Overall wholesale costs rose 11% in 2024 due to higher energy and emissions costs, while capacity costs decreased 5%. Imports from Canada were somewhat constrained due to water levels and operational considerations, and scarcity pricing remained rare. During the June heatwave, the system remained reliable, with reserve resources activated and no conservation appeals required.

Looking ahead, preliminary 2026 budgets show modest increases, with costs primarily recovered from market participants. The 2025 CELT report projects steady growth in electricity demand through 2034, driven by electrification, while behind-the-meter solar is expected to reduce peak loads and ease transmission constraints. Long-term transmission planning is underway, with proposals for Northern Maine to Southern New England upgrades due in September 2025, and FERC Order 2023 now in effect, establishing the transitional and regular interconnection study windows through 2026.

Policy and Project Updates

PUC Case No. 25-0339 Resilience Proceeding: The Vermont Department of Public Service is leading a resilience investigation of the state's electric grid under the Public Utility Commission. This initiative is not a contested case but aims to develop recommendations for enhancing grid resilience amid climate change, growing electrification, and evolving technologies. Three working groups—focused on planning, valuation, and measurement—have convened with utilities, stakeholders, and technical support from

Lawrence Berkeley National Lab and the University of Texas at Austin. Discussions have examined resilience frameworks in other states, utility planning practices, and emerging solutions such as energy storage, undergrounding, and storm hardening.

Anne Margolis with the Vermont Department of Public Service noted the diversity of utility valuation methods, ranging from budget allocation to benefit-cost analyses, and interest in establishing state-level resilience targets. Planning discussions highlighted evolving construction standards, climate-informed risk modeling, and prioritization of investments based on vulnerabilities. Measurement efforts are exploring updated resilience metrics beyond traditional reliability measures, with attention to utility differences, technological limitations, and the interaction of interventions like vegetation management. Next steps include consolidating working groups, refining frameworks, and issuing a straw proposal for feedback, with recommendations to the Commission expected by early fall.

PUC Case No. 24-3351 Update: The Public Utility Commission has opened an investigation into potential transmission system improvements identified in the 2024 Vermont Long Range Transmission Plan. Tom Knauer with the Vermont Public Utility Commission shared that information requests have been issued, and utilities and other stakeholders recently submitted filings. The PUC plans to review these submissions and hold a workshop in August to discuss next steps.

2024 VT Long-Range Transmission Plan – NTA Analysis Update

Kamran Hassan and Cam Twarog with GMP provided an update on the preliminary NTA Study work underway, noting the significance of the time series analysis performed by VELCO to better understand the frequency and duration of potential transmission issues. Unlike traditional long-range plan assessments, which relied on worst-case scenarios, this new approach accounts for the duration of peak load events, enabling more granular and realistic comparisons between non-transmission alternatives (NTAs) and traditional transmission solutions. GMP highlighted that these updated modeling approaches allow for a more accurate evaluation of NTAs and help inform the upcoming planning cycle.

In reviewing zone-specific findings, GMP focused on the northern and northwest zones previously flagged for reliability concerns. The northern zone was found to require roughly 75 MW of load reduction during peak periods, but refined analysis showed that total energy needs for mitigation are lower than earlier estimates. Illustrative load curves indicated, for example, that the evening peak in the northern area dropped from 375 MWh to 230 MWh. In the northwest zone, summer load shapes demonstrated increased flexibility for energy shifting due to solar generation, allowing for greater management of peak loads without stressing transmission infrastructure.

The presentation addressed the role of electric vehicle (EV) charging management in mitigating peak load concerns. GMP currently operates two programs—a time-of-use (TOU) rate and an event-based rate that curtails charging during forecasted peaks. Modeling assumptions included 50% of EVs being controllable, though actual participation rates exceed this level. Revised charging curves, which shift charging to later in the evening, were shown to significantly reduce morning and evening peaks, lessening reliance on transmission upgrades. Discussions also highlighted behavioral and trust factors in controllable resources, noting that operators depend on real-time data and historical program performance demonstrates high reliability of load control measures.

GMP also presented updates on transmission line ratings, noting revisions to ISO planning procedures (PP7) that account for ambient temperature effects. Winter planning assumptions are moving from 50°F to 20°F conditions, increasing line capacity by 10–25% and reducing critical load concerns. It is unclear when ISO-New England will implement these adjustments in their base case planning scenarios.

GMP also noted that existing storage assets, including powerwalls and utility-scale batteries, have already reduced Vermont's peak by approximately 45 MW during past events. Modeling indicated that integrating controllable storage with revised EV charging behavior can maintain loads below critical thresholds in the northern and northwest zones.

Next steps will focus on coordination of other NTAs, defining equivalence standards under varying system conditions, and continued collaboration with stakeholders to refine assumptions and finalize analyses for future planning cycles.

Attendance

* Indicates voting member
** Indicates alternate

Public Sector

*Taylor Newton, Regional Planning Rep
**George Gross, Regional Planning rep
**Steve Crowley, Environmental representative
*Michael Kirick, Commercial representative
**Molly Mahar, Commercial representative

Transmission Utility (VELCO)

*Marc Allen, VELCO

Distribution Utilities Providing Transmission (GMP, VEC)

*Kamran Hassan, GMP
**Doug Smith, GMP

Large Transmission-Dependent Distribution Utilities (BED, WEC, GF)

*JJ Vandette, WEC
*Chris Cole, GF Power

Transmission Dependent Distribution Utilities (Municipals)

Michael Gadway, Village of Ludlow
Jackie Pratt, Stowe Electric
Michael Lazorchak, Stowe Electric
Scott Johnstone, Morrisville Water & Electric

Supply & Demand Resources

*Jonathan Dowds, Supply Representative
*Tom Lyle, BED

Non-Voting Members

Lou Cecere, PSD

Staff

Shana Louiselle, VELCO

Guests

Andrea Cohen, VEC
Anil Adhikari, National Grid
Anne Margolis, PSD
Betsy Bloomer, VELCO
Brian Connaughton, VELCO
Brian Hall, VEC
Cam Twarog, GMP
Cyril Brunner, VEC
Dave Carpenter, DRM
David Mullett, All Earth Renewables
Hannes Pfeifenberger, Brattle Group
John Moura, NERC
Kerry Schlichting, ISO-NE
Khalid Osman, VELCO
Louis Porter, WEC
Lucas Looman, VELCO
Marc Allen, VELCO
Morgan Casella, DO
Paul Lambert, EVT
Paul Nadeau, BED
Peter Fitzgerald, INS Engineering
Philip Picotte, PSD
Sarah Adams, ISO-NE
Tom Dunn, VELCO
Tom Knauer, PUC
Warren Coleman, MMR
Zakia El Omari, VELCO