Northern and Northwest Area Reliability Plan

This document serves as Green Mountain Power's (GMP) reliability plan for the Northern and Northwest Reliability areas identified in the 2024 Long Range Transmission Plan.

Summary

VELCO's *2024 Long Range Transmission Plan* (*LRTP*) identified potential reliability concerns in Northern and Northwest Vermont in the 10-year planning horizon beginning in 2033. These concerns arise under the assumptions of high load growth due to electric vehicle (EV) adoption without charging management programs, alongside additional heat pump adoption. The underlying load forecast has been materially reduced in the recent months as part of the forecasting effort for the 2027 LRTP.

As a follow up to the 2024 LRTP, under Docket 7081, GMP as the lead distribution utility (DU), has led the Non-transmission Alternative (NTA) Working Group, the Geographic Targeting Subcommittee, and the Vermont System Planning Committee (VSPC) general membership in the following analysis to determine a suitable non-transmission alternative for the identified concerns. This has included:

- A VELCO-led 8760 time-series analysis of each reliability area to determine critical load levels.
- The update of assumptions to include the peak-shaving behavior of existing storage resources prior to transmission contingencies occurring, as they operate today.
- The participation in various working groups and subcommittees, including the NTA Working Group, the Geographic Targeting Subcommittee, as well as the participation in PUC investigation into the 2024 LRTP: Case No. 24-3351-INV.

The updated load forecast for the 2027 LRTP shows roughly 145 MW of reduction in EV peak loads and over 100 MW of reduction in heat pump peak loads, meaning that the need to build a transmission solution has been deferred beyond the 10-year study horizon by considering existing peak-shaving storage resources alongside the reduction in load growth projections. Furthermore, if load growth happens at the rate studied in the 2024 LRTP, the following actions will need to be taken by the DUs:

- Refinement of EV charging management programs to reduce the charging spike following a time-of-use event and to encourage more charging in the late evening and early morning hours.
- Tracking of metrics related to peak management, including but not limited to EV charging management adoption rates, EV program coincident-peak load reduction, and active and proposed storage at each substation

The following pages describe the background behind the 2024 LRTP and subsequent NTA analysis, the proposed accounting for existing NTA resources, and the actions that are needed if load growth occurs at the rate shown in the 2024 LRTP. The approach outlined in this Plan defers the need for transmission solutions through the continued use of existing EV charging and storage programs, with proposed changes to these programs if EV loads reach the level forecasted in the 2024 LRTP. The Project-Specific Action Plans for both the Northern and Northwest areas are included as an appendix to this Reliability Plan.

Reduction of Load Forecast in 2027 Long Range Transmission Plan:

As part of the 2027 LRTP, the underlying forecast of EV charging and heat pump loads has reduced significantly due to decreased demand and adoption by consumers, especially in the 2033 study year that was identified as the first year of concern in the 2024 LRTP cycle. Figure 1 and Figure 2 show the proposed forecast annual MWh impact of EV charging and coincident peak demand of EV charging respectively[1].

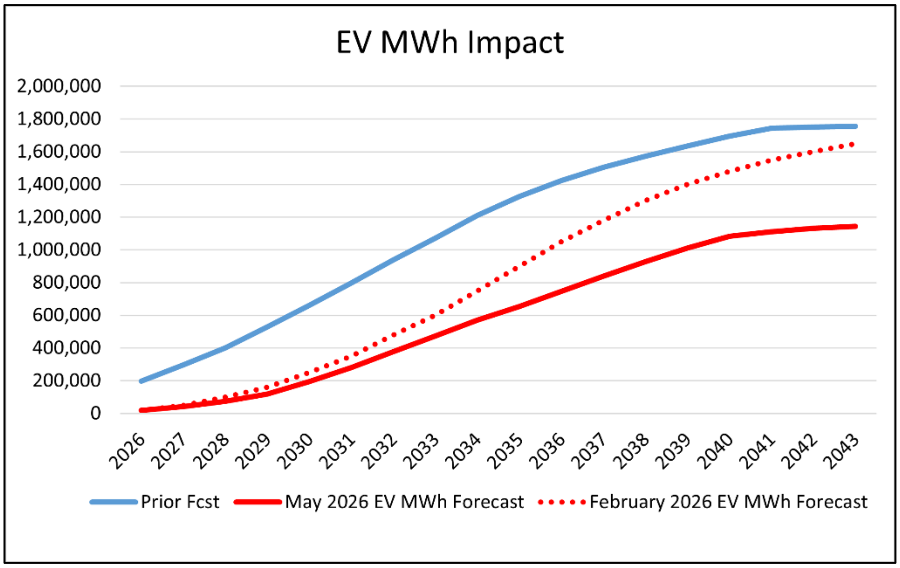

Figure 1: Updated EV forecast showing significantly lower annual EV charging energy in the 2033 study year.

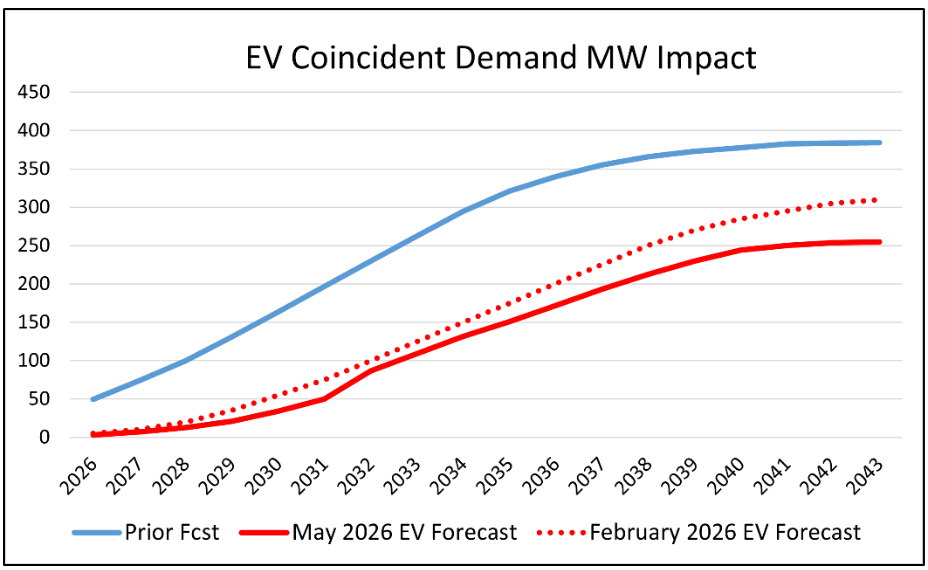

Figure 2: Updated EV forecast showing significantly lower peak coincident charging from EV charging in the 2033 study year.

[1] This presentation can be found on the Vermont System Planning Committee's website.

This revised forecast was discussed at numerous Load Forecasting subcommittee meetings beginning in the spring of 2025 and will be used as the basis for the 2027 Long Range Transmission Plan. A few underlying assumptions change in this forecast, including the number of EV sales each year and the percent of vehicles enrolled in managed charging programs. VELCO provided an updated EV forecast from May 2026 that further reduced EV peaks loads than what was presented at the Load Forecasting meeting in February 2026 to reflect a reduced EIA EV sales target. Due to the preliminary nature of this updated forecast, it is difficult to accurately translate the statewide EV coincident peak demand into a time-series forecast for the Northern Zone, but the fact still remains that the revised forecast reduces EV peak coincident demand from roughly 262 MW in 2033 to 109 MW in 2033, and reduces the total annual charging energy from roughly 1 million MWh to 470,000 MWh for the same time period.

Similarly, Itron has revised the coincident peak contribution of heat pumps in the winter months based on the results of the 2024 Heat Pump Study performed by Ridgeline Energy for the state of Vermont. Due to lower-than-expected energy consumption by heat pump owners in Vermont (especially in regions with access to natural gas, like the Champlain Valley), the total energy that heat pumps are forecasted to use in Vermont and heat pumps' contribution to winter peak loads has significantly decreased. The result of these two forecast changes is a net reduction in the energy that needs to be shifted as part of this NTA analysis on peak winter days.

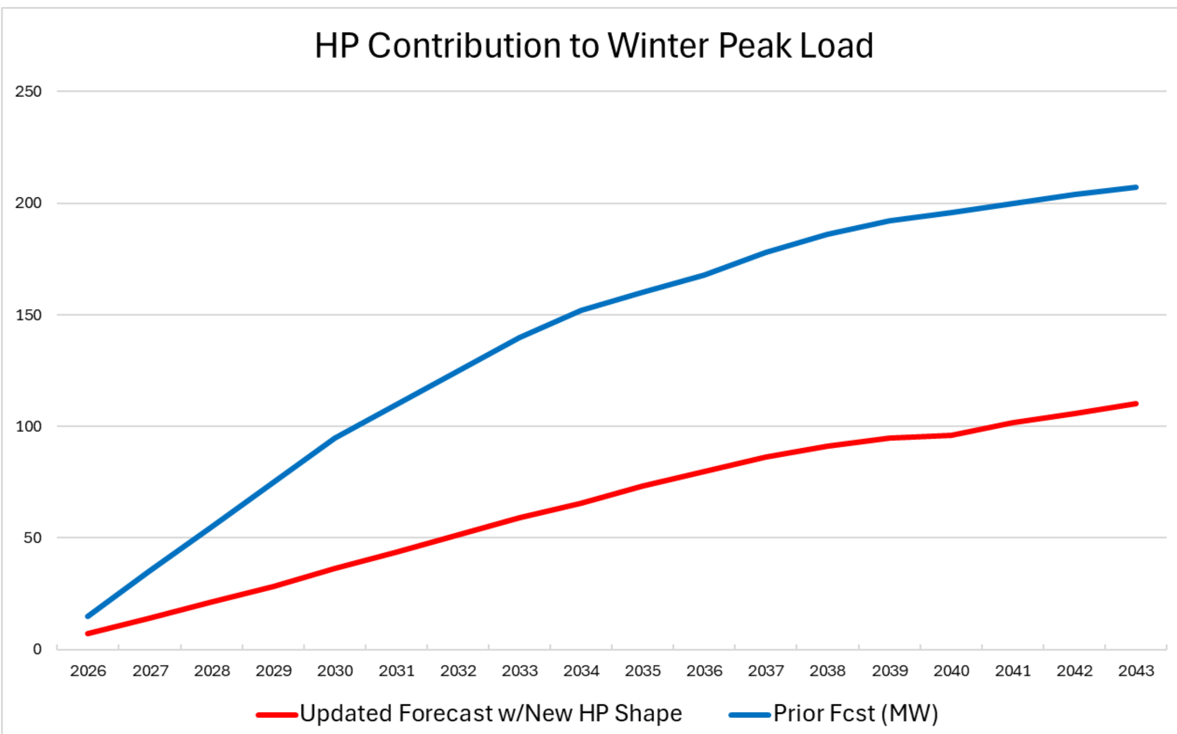

Figure 3: Graph comparing heat pump peak load contributions between the 2024 LRTP and the revised forecast for the 2027 LRTP.

The result of this forecast revision is a drop in heat pump peak demand contribution from 140 MW in 2033 under the original assumptions to 59 MW under the revised assumptions, based on the results of the Ridgeline heat pump study. This drop in forecasted demand is projected to be proportionally larger in regions that have access to natural gas, meaning that the Northern and Northwest zones will see proportionally larger load reductions in heating demand than the rest of the state in the 2027 LRTP. The 2027 LRTP will use this new forecast and will further quantify the impact of the forecast reductions on the needs of the Northern and Northwest areas.

Due to the preliminary nature of the data outputs of the 2026 forecast, zonal values and time series values are not yet available. The following table uses each zone's proportion of uncontrolled EV and HP load in the 2024 forecast and projects the load reductions in the 2026 forecast to the zonal level:

	Original 2033 EV Load (from 2024 LRTP)	**Estimated 2033 EV Load (from 2027 LRTP)**	**EV Load Reduction**	**Original 2033 HP Load (from 2024 LRTP)**	**Estimated 2033 Heat Pump Load (From 2027 LRTP**	**HP Load Reduction**	**Total Estimated Load Reduction**
Northern Zone	92.7	38.1	54.6	99.6	42.0	57.6	**112.2**
Northwest Zone	134.5	55.3	79.2	102.1	43.0	59.1	**138.2**

This estimation shows that the upcoming forecast could reduce the peak loads in the Northern zone by over 100 MW in the winter of 2033. This reduction in EV and HP assumptions is more than enough to defer the need for a transmission solution, as the maximum load reduction needed in 2033 using the 2024 LRTP was 75 MW. As more data for the forecast becomes available and as the 2027 LRTP progresses, this estimation will be validated, but the revised 2026 forecast has reduced the peak loads enough to defer the need for a transmission solution before any additional EV program modifications are considered or existing storage resources are dispatched.

The following analysis and description of the proposed solution illustrates that there are many factors that defer the need for a transmission solution, with the revised load forecast being the largest factor. If loads are not reduced as much as predicted in this forecast and up to 75 MW of load reduction is required in the Northern zone, this reliability plan shows that existing storage and modifications to existing EV programs can defer the need for a transmission solution alone.

Background:

On June 28, 2024, VELCO published the 2024 Vermont Long Range Transmission Plan (LRTP, The Plan) which identified the potential for reliability concerns on the transmission system under scenarios of high load growth and multiple transmission elements out of service. The LRTP identified the Northern and Northwest areas of concern as the two areas which require a Non-Transmission Alternative analysis (NTA analysis) under Docket 7081 due to their timing being within a ten-year horizon.[2]

The geographic area for the Northern Vermont zone is bounded by the Plattsburgh, Williston, Granite, and Littleton substations. The Northern Vermont Reliability concern is the result of load growth, primarily driven by forecasted electrification of the transportation and heating sectors. The *Vermont Road Map*

[2] The Plan also identified two other potential reliability concerns, but their timing is outside of the 10-year horizon and further analysis is not needed at this time.

forecast – originally developed in 2023 for the 2024 Vermont Long Range Transmission Plan – assumes that future EV loads will have uncontrolled profiles, meaning that peak EV loads would overlap with peak base and heating loads. Figure 4 shows the original load shape from the 2024 LRTP in the Winter of 2033. There is a peak load reduction of 75MW/230MWh, and there is a need for both a morning and night load reduction in the Northern area on some days.

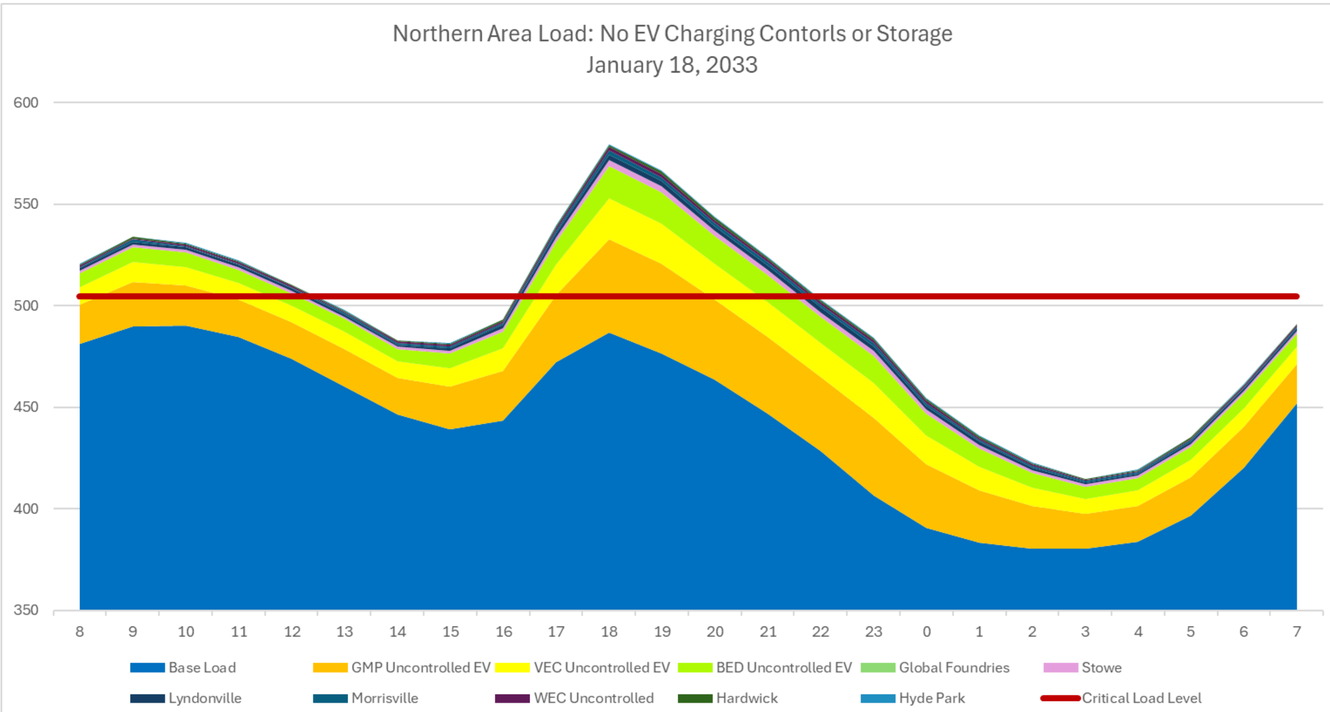

Figure 4: Northern Zone Load from VELCO's frequency/duration analysis as part of the follow-up to the 2024 LRTP.

The geographic region for the Northwestern Vermont area includes the Northern Vermont area and extends south to include the Middlebury and Florence areas. It is bordered electrically by the Plattsburgh, West Rutland, Granite and Littleton substations. Similarly to the Northern zone, the Northwest Vermont Reliability concern is caused by the forecast of high load growth in EVs and heat pumps and therefore can be resolved using the same methodology. Figure 5 shows a Summer peak day from the original 2024 LRTP in the Northwest Area. There is a peak load reduction need of 80 MW / 318 MWh in this zone on a peak summer day in July 2033.

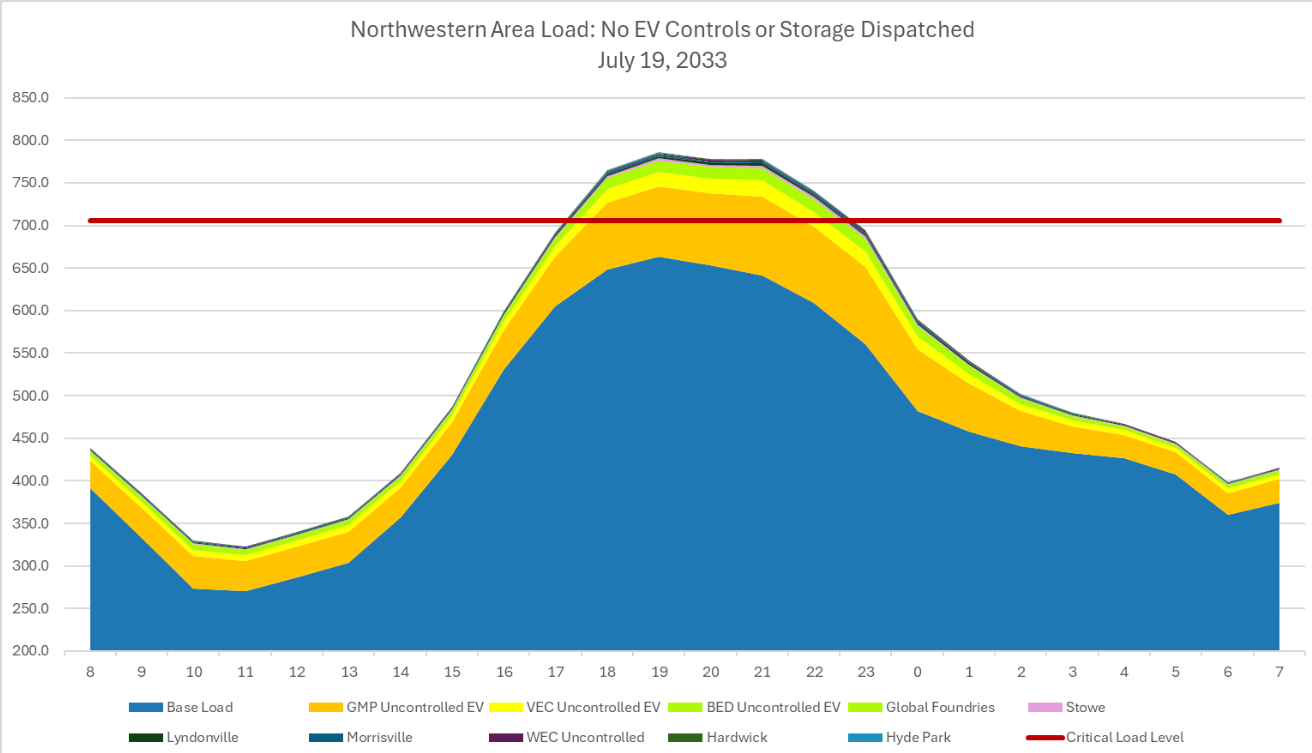

Figure 5: Northwest Area load from VELCO's frequency/duration analysis as part of the follow-up to the 2024 LRTP.

As part of the 2024 LRTP, VELCO proposed the following transmission upgrades to address these reliability concerns:

- Northern Area: Add a second transmission line between VELCO's Essex and Williston substations and replace three 115/34.5 kV transformers (Queen City, Barre and Tafts Corners). The cost estimate is a total of $153M.
- Northwest Area: Rebuild the Middlebury-West Rutland 115 kV transmission line and replace one 115/46 kV transformer (Middlebury). The cost estimate for this work is a total of $228M.

In the months following the publication of the 2024 LRTP, GMP, VELCO and the other DUs worked closely together to revise assumptions that were used in the 2024 LRTP and to perform additional analysis to determine the applicability of storage of EV charging management to defer these reliability concerns. The NTA analysis was discussed over ten times since January 2025 at the VSPC and its subcommittees.

All publicly available materials have been uploaded to the VSPC website. GMP, VELCO, BED, and VEC also provided additional public engagement through PUC investigation into LRTP: Case No. 24-3351-INV.

The description and analysis of these reliability concerns are based on the original 2024 load forecast used in the 2024 LRTP, not the revised load growth forecast which shows dramatically lower peak loads for EV charging and heat pumps which is discussed in the following section. Therefore, GMP suggests that load growth continued to be monitored in the following years prior to the actions described below are taken. GMP, VELCO, and the NTA Working Group have reached the conclusion that the need for a transmission solution has been deferred beyond 2033.

Further discussion of the Northern and Northwest areas can be found in the attached Project-Specific Action Plan.

Description of Non-Transmission Alternative Solution:

In addition to the high levels of load growth forecasted in the 2024 Long Range Transmission Plan compared to updated forecasting, the Plan also changed several critical assumptions from previous year's plans resulting in higher 2033 load levels than previous plans. The two assumptions that this reliability plan discusses in detail are those behind existing EV charging management programs and existing distributed and utility scale storage systems.

As discussed above, the magnitude and timing of the reliability concern are sensitive to the load forecast assumptions which have since been updated and materially reduced under the new forecast for the 2027 Long Range Transmission Plan. The following analysis shows that the use of existing storage and slight modifications to existing EV charging programs defer the need for transmission upgrades even with a very high load forecast that no longer is valid. While these actions are no longer recommended, they have been left in the report to demonstrate potential solutions if future load forecasts are modified upwards.

Using Existing Storage for Peak Management:

The most notable assumption that was updated as part of the NTA analysis was the inclusion of peak shaving storage that is already interconnected on the system. GMP alone has over 50 MW of distributed and utility scale storage that it dispatches each month to reduce GMP's load at Vermont's peak hour, thus reducing its Regional Network Service (RNS) payments each month. GMP also uses this storage to reduce its Forward Capacity Market (FCM) payments during ISO-NE's single highest load hour each year. Since this storage is dispatched agnostically to any transmission system needs, it was determined by the NTA Working Group that existing storage could be used as a resource to shift energy around and keep loads below critical load levels.

Statewide peak loads and regional annual peaks have a high correlation to the forecasted reliability need hours. GMP performed a time series analysis of the Northern, Northwest, and state-wide load profiles and determined that statewide peak load hours are good proxies for hours that need load reduction in the study areas to maintain reliability. All of the top 50 statewide hours in January 2033 were hours that exceeded critical load levels in the Northern area in the 2023 forecast. Similarly, the top load hour in all months were coincident between the Northern area and statewide loads. Given the seasonal and weather driven nature of these forecasted peaks, this pattern is expected to continue. GMP's analysis concludes that current strategies for this storage resource, without modification, are expected to help meet reliability needs for 2033 should the 2024 LRTP load forecast be used in the future.

It is essential that the peak-shaving resources that are dispatched for the Northern and Northwest areas are located within these areas as they currently are.

Electric Vehicle Charging Management Updates:

The 2021 LRTP assumed that 75% of EVs would be under charging management programs in the future, while the 2024 LRTP assumed 0% of EVs would be under a management program. To date, many DUs are already effectively deploying EV charge management programs. Subsequently, the NTA working group worked to better understand and quantify the levels of existing charging management that exist today and ensured that these assumptions were included as part of the NTA analysis.

The NTA Working Group received data from GMP, VEC, and WEC about enrollment rates in their current EV management programs who estimated their capabilities at 65%, 50%, and 33% of registered EVs respective to their service territories. GMP then applied a revised theoretical EV charging curve, designed to solve this specific overload, to each DU's EV load in the study cases for the percentage of vehicles that are assumed to be under a managed charging program and left the remainder of vehicles under an uncontrolled charging shape.

GMP's estimate of 65% of fully electric vehicles under a managed charging program takes today's estimated participation rate and allows for a drop in enrollment percentage in the upcoming years. Figure 6 shows the cumulative enrollment percentage for GMP customers at the Northern, Northwest, and statewide levels. Today's enrollment rates are in the low 70% and do not differ drastically between areas in the state.

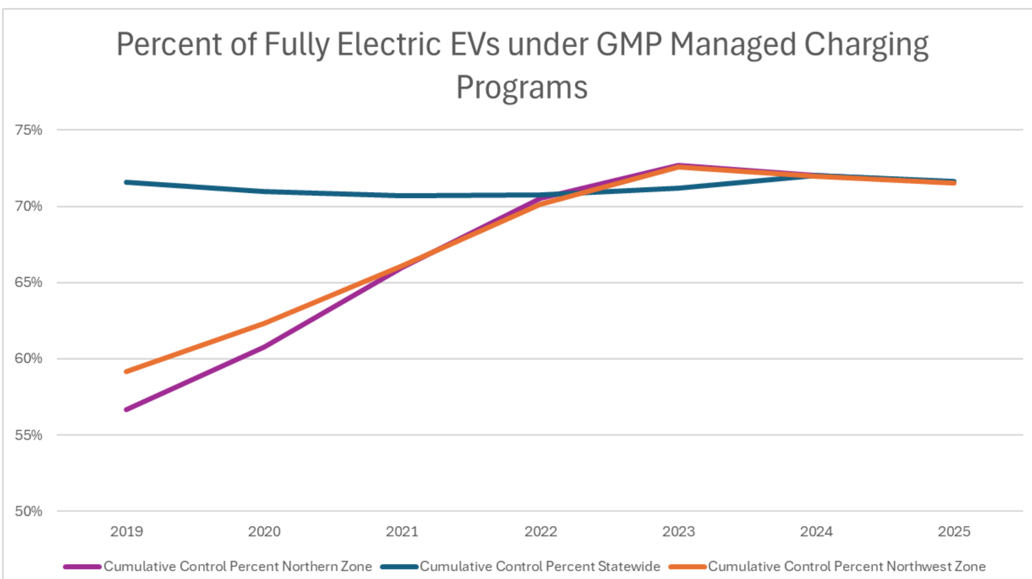

Figure 6: Estimated percentage of vehicles under a managed charging program in GMP's territory.

Figure 7 shows the difference between the original EV charging curve that was used in the LRTP and the illustrative managed curve that was developed for the NTA analysis. The difference between these two curves is the timing of the peak charging load; the controlled curve shifts the peak later into the night while also reducing the "bounce back" effect that is seen in a time-of-use program. The revised curve was designed to shift peaks later in the evening while keeping a realistic portion of vehicles under no control and under existing programs. The total energy remains the same between the two curves, meaning that all customers have vehicles that are fully charged by the morning commute.

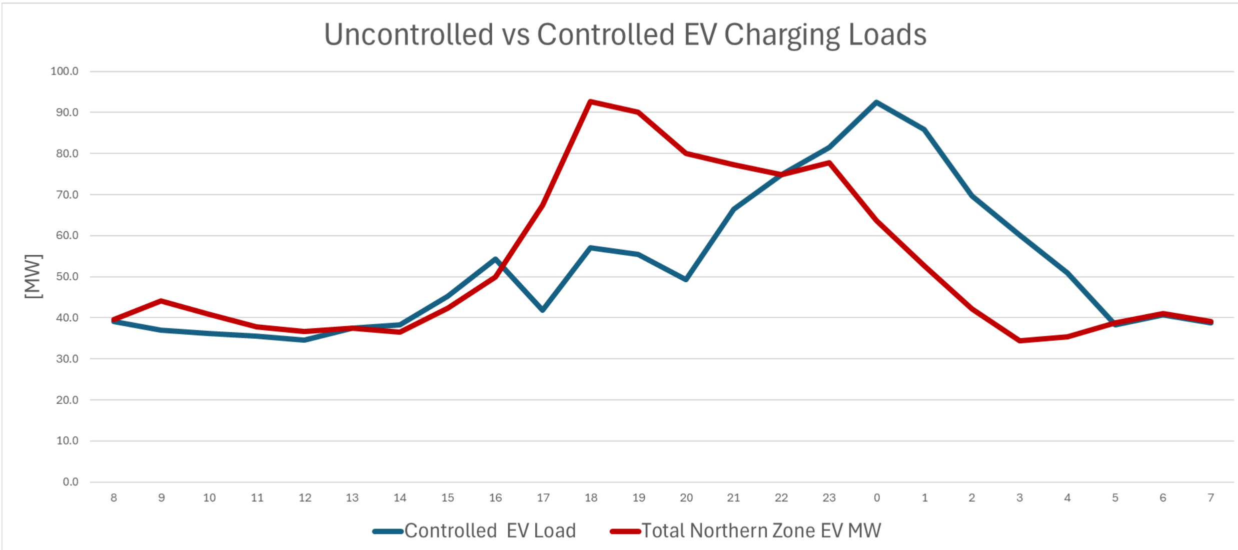

Figure 7: Original EV charging shape (red) vs the combination of uncontrolled charging and revised managed charging at today's adoption rates (blue).

The shift in peak timing was achieved by modeling multiple time-of-use windows to distribute charging start times and by modeling a portion (consistent with today's enrollment rates) of customers in an event-based charging management program like GMP's Rate 72. The following table contemplates how an EV curve like the one in Figure 7 could be constructed through three different TOU windows and an event-based program dispatched as within today's operating parameters for this program:

Option	Uncontrolled	Rate 72 Weight	Rate 72 Window (approx)	Rate 74 (0 hr)	Rate 74 (+2 hr)	Rate 74 (+4 hr)	Rate 74 (+6 hr)
Option 1	60%	8%	~19–22	14%	7%	7%	4%
Option 2	60%	7%	~20–23	13%	9%	7%	4%
Option 3	60%	10%	~18–21	10%	10%	7%	3%

The total uncontrolled percentage is a conservative weighting of the Northern Area based on data from the Distribution Utilities (DUs). The conservatism is based on the data the DUs provided, and also serves to acknowledge that future program changes could potentially reduce enrollment rates if not implemented thoughtfully. The percentage of uncontrolled customers means that with between 8-10% of customers on an event-based program, and 28-30% of customers on a staggered TOU rate (leaving 60-64% of customers uncontrolled), the desired curve can be closely replicated. Figure 8, Figure 9, and Figure 10 show what these different program modifications could look like in comparison to the goal curve. The goal curve is subject to change given future load shapes. Minimal program modifications at conservative adoption levels, the overall EV load shape can largely be shaped to place peak loading hours at the desired times of the evening.

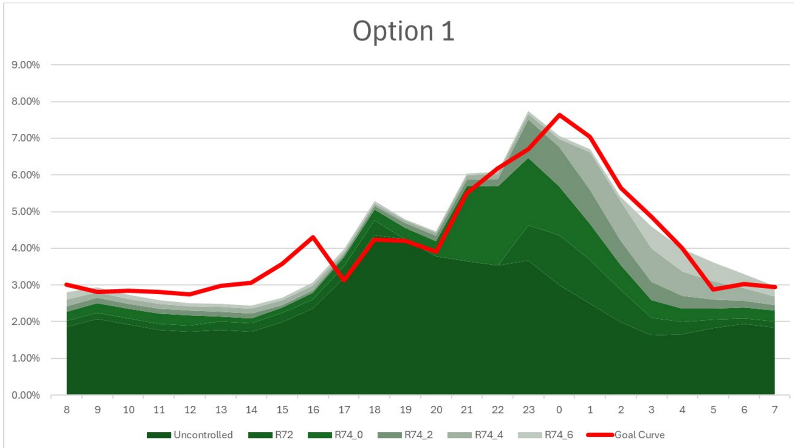

Figure 8: Option 1 to reconstruct the desired curve with feasible program modifications.

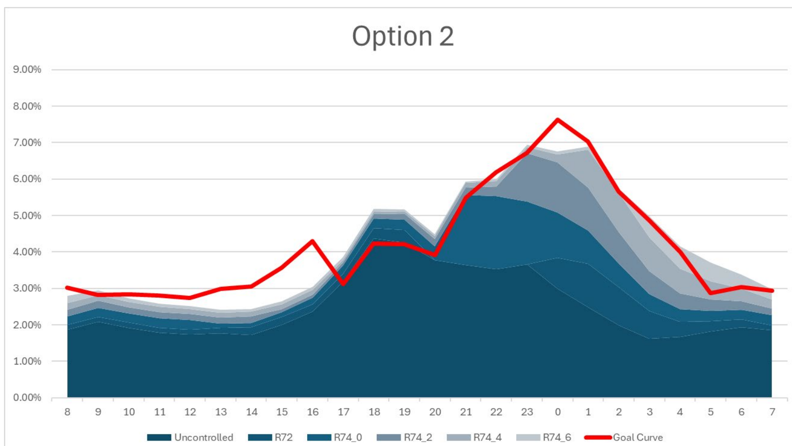

Figure 9: Option 2 to reconstruct the desired curve with feasible program shifts.

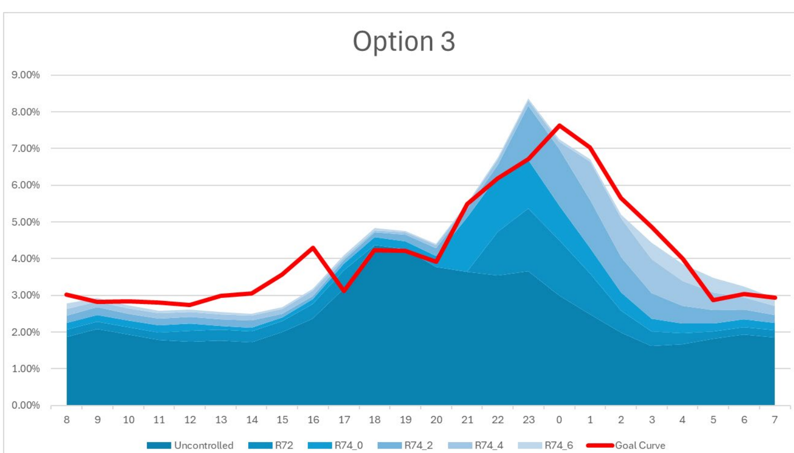

Figure 10: Option 3 to reconstruct the desired curve with feasible program shifts.

The percentage of customers enrolled in a managed program vs. those with unmanaged charging was modeled at levels that DUs provided to GMP and are consistent with their current enrollment rates today, showing that modifications to existing programs can defer transmission upgrades at very high EV adoption rates across Vermont.

Northern Area:

The 2024 Vermont Long Range Plan found that there was a need for 75 MW/ 230 MWh of load reduction in 2033 in the Northern area. The first step that GMP and the NTA working group took was to revise the EV charging load shape to better reflect a redesigned tariff at adoption rates that are consistent with today's. The modification reduced from the need from 75 MW/230 MWh to 42 MW/102 MWh as shown in Figure 11.

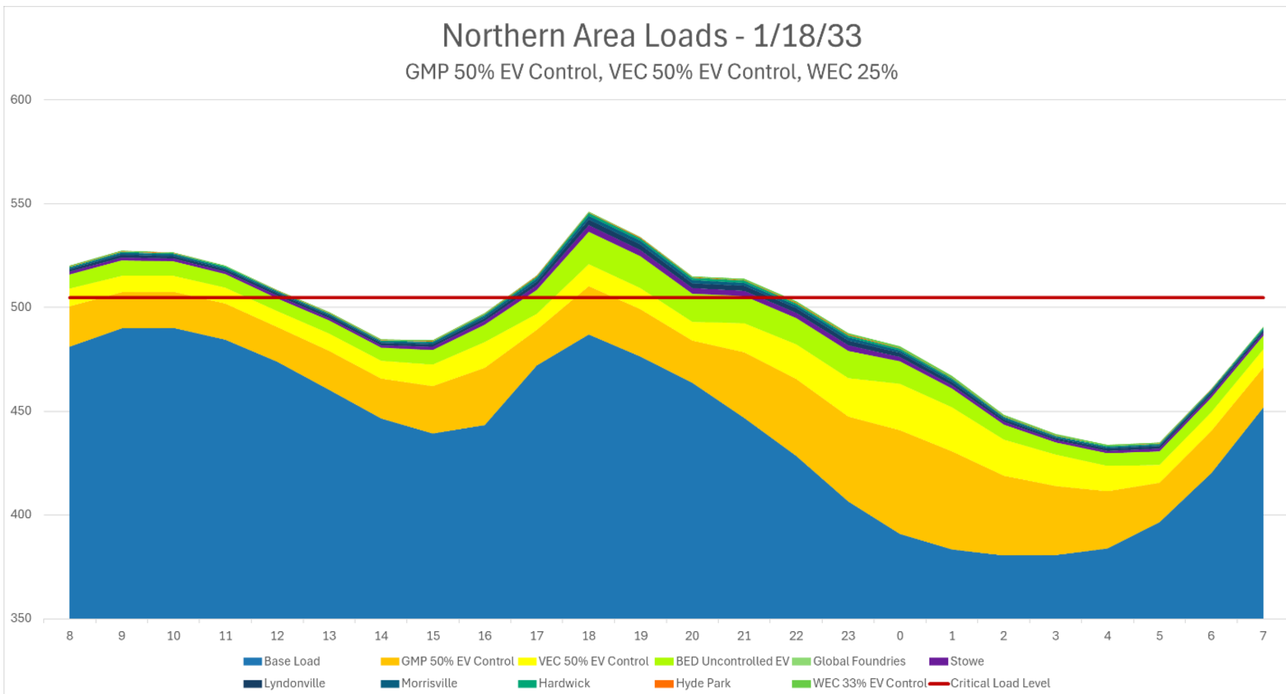

Figure 11: Northern area load shape after including EV charging management programs.

The NTA Working Group then determined that existing storage resources that are used monthly for peak shaving should be included in the NTA analysis since they are already used on the coldest days of the year and will continue to be used this way. The Northern area currently has the following storage resources being used for peak shaving:

Northern Area Active Storage		
	MW	**MWh**
GMP Residential Storage (BTM)	11.7	31.4
GMP Utility-Scale Storage	16.1	45.3
VEC Storage	7.5	30.4
GF Storage	15	60
Total	**50.3 MW**	**167.1 MWh**

There is enough storage capacity interconnected today in the Northern area to shift the remaining peak loads into the early morning hours and defer the need for a transmission solution, even when considering a conservative 85% round trip efficiency into account for the batteries. Figure 12 shows the resultant load profile with storage and EV managed included, as well as the state-of-charge of the batteries in this region. Notice how the batteries are able to return to 100% charge over the course of a day, so that if multiple peak days occur in a row, these resources will remain effective.

All of the resources modeled in the above steps are currently located within the Northern area or (in the case of EVs) are forecasted to be within the Northern Zone. Participation within managed EV programs will have to remain or exceed the statewide participation rates that were discussed above in order for this analysis to hold true.

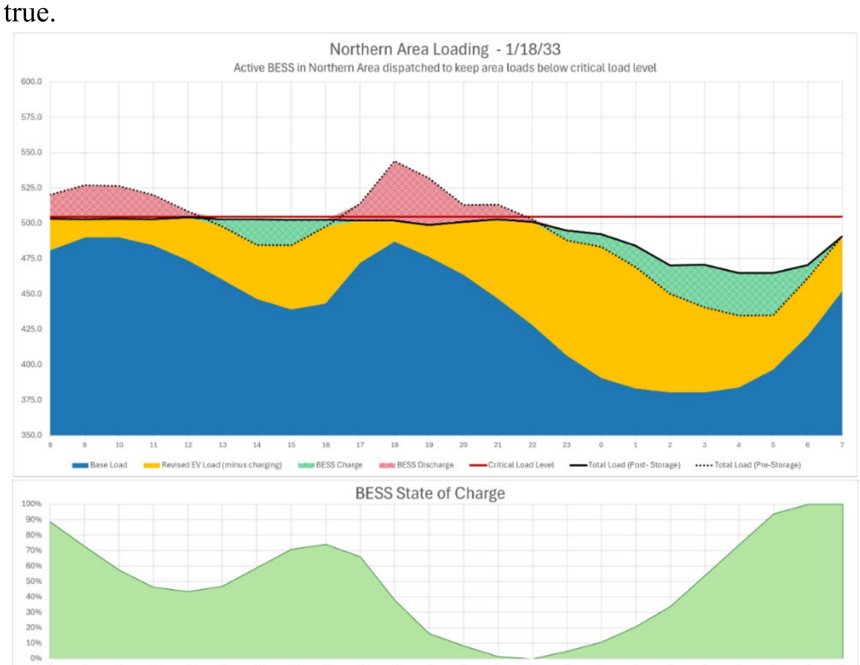

Figure 12: Northern Area load, including EV management and storage dispatch.

Northwest Area:

The analysis performed for the Northwest area is very similar to the Northern area, with the exception that the Northwest area also has a reliability exposure in the summer months. After applying the same assumptions around EV charging management as the Northern area, the load reduction needs reduced from 80 MW/ 318 MWh to 32 MW / 106 MWh as shown in Figure 13.

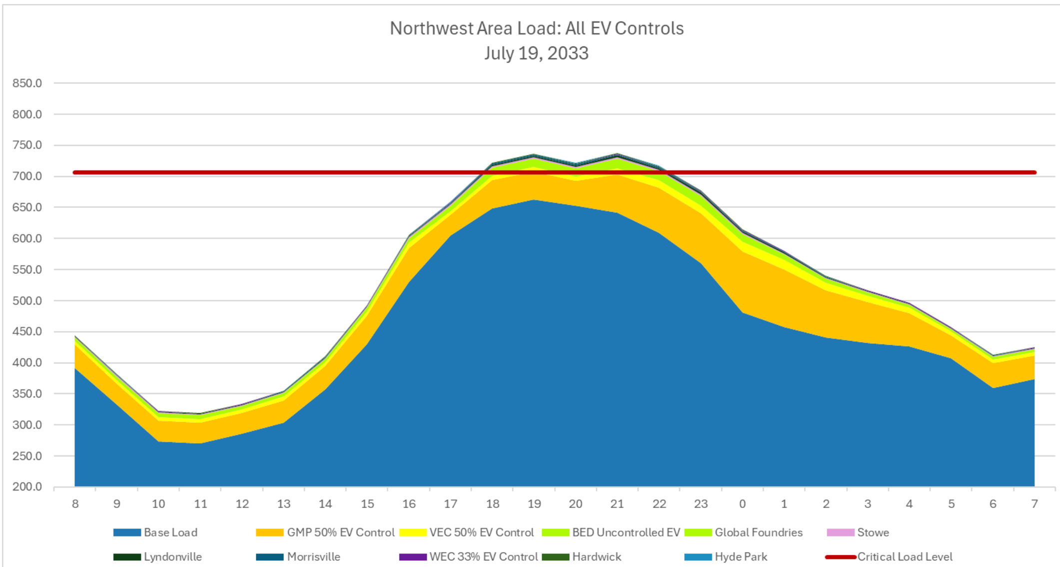

Figure 13: Northwest Area load with EV management taken into account.

The existing storage resources in the Northwest area were then applied to reduce the peaks further. As shown in the following table, there is enough storage in the region to defer the identified transmission need, similarly to the Northern area. Figure 14 shows the Northwest area load following EV management and storage dispatch as well as the state of charge of the batteries in this zone. All storage has the time to recharge to 100% by the following morning, in case a multi-day heatwave causes similarly high loads for more than one day.

Northwestern Area Active Storage		
	MW	**MWh**
GMP Residential Storage (BTM)	15.9	42.7
GMP Utility-Scale Storage	24.1	72.9
VEC Storage	7.5	30.4
GF Storage	15	60
Total	**62.5 MW**	**206.0 MWh**

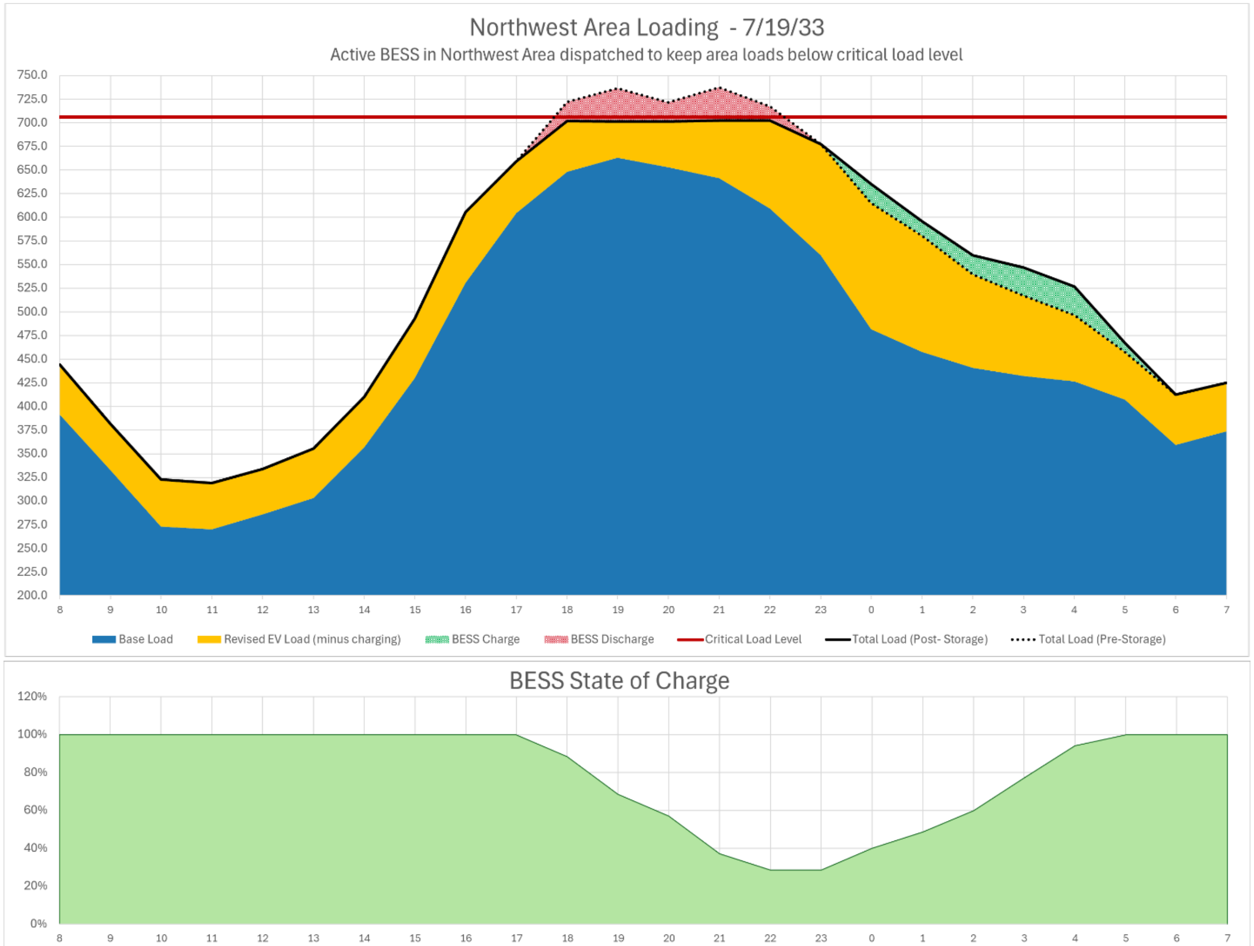

Figure 14: Northwest area loads following EV management and storage dispatch.

The NTA working group did not consider the growth of BTM and utility scale storage in this analysis which is likely to increase at a similarly rapid pace compared to forecasted load growth, increasing the amount of flexible resources available to manage peak loads. The amounts of proposed storage are discussed in the Project Specific Action Plan.

NTA Working Group Recommendations:

Existing Storage Dispatch:

The timing of the reliability concerns that were identified in the 2024 LRTP are dependent on the timing and extent of load growth due to EV and heat pump adoption[3]. GMP and the VSPC recommend the following actions be taken.

---

[3] The forecast that was used in the 2024 LRTP shows significantly more growth in EV and heat pump loads in the 2033 study year than the updated forecast that will be used in the 2027 LRTP. The 2024 load forecast was used in this analysis, although the revised 2027 forecast could change the need to revise EV charging control programs.

Northern Area: The existing 50.3 MW/167.1 MWh of storage in the Northern area will continue to be dispatched as a load reducer in the manner that it is dispatched today by targeting statewide monthly RNS peaks and annual FCM peaks.

Northwest Area: The existing 62.5 MW/206 MWh of storage in the Northwest area will continue to be dispatched as a load reducer in the manner that it is dispatched today by targeting statewide monthly RNS peaks and annual FCM peaks.

EV Program Modifications:

Should the EV load growth occur at levels projected in the 2024 LRTP, the DUs will have to modify their existing EV TOU programs to shift peak loading hours later into the evening and to reduce any new peaks that are caused at the end of the TOU window, when all vehicles begin charging at the same time.

At this time, these changes are not needed. Should forecasts require these, GMP would implement a TOU program that has multiple staggered TOU windows (with on peak hours of 3pm-12am, 4pm-1am, 5pm-2am, for example) to more evenly distribute the impact of many vehicles coming online during the off-peak hours. GMP would continue its Rate 72, event-based program to allow for flexible management of a portion of its EV load. Other DUs have proposed the following solutions:

- A multi-tiered TOU rate like the one GMP suggests
- A DERMS-based approach to actively manage charging peak loads and ensure all vehicles are charged by the time they are needed.

These program changes would help defer the identified transmission needs by shifting charging away from peak hours, eliminating post-TOU rebound spikes, and by ensuring cars have a full charge in the morning. GMP and other DUs have seen that TOU and event-based programs are effective at changing charging load shape today. Modifying the program timing is expected to have a similar impact to today's programs but be better aligned with the timing and needs of future peak loads.

EV and Load Growth Metric Tracking:

In addition to these actions, the affected DUs will continue to track the metrics below across their systems. VELCO can support these efforts by continuing to define and refine data requirements for these technologies to be included in future transmission planning studies.

- **EV charging management enrollment rates**, expressed as a percentage of total vehicles within each service territory.
- **Customer Opt-out rates** for those enrolled in EV charging management programs.
- **Coincident peak EV load reductions,** quantified as the megawatts of EV charging reduced during system peak hours because of management programs.
- **Planned program refinements**, including changes to Time-Of-Use windows, event frequency, event duration, etc.)
- **Behind-the-meter (BTM) and utility scale storage capacity**, reported in MW/MWh at each substation or bus, along with associated control strategies and dispatch methodologies.

- **Available flexible load capacity**, including C&I customers, reported in MW/MWh at each substation and operational strategy used to call these events.

Additional Factors Reducing the Need for Transmission Solution

The results of the 2024 LRTP are dependent on the assumptions that were used when its analysis was performed, and therefore the results of this NTA study are dependent on those assumptions coming to fruition for the 2027 LRTP. There are numerous additional factors at play that reduce the need for a transmission solution for the Northern and Northwest areas, not limited to the following:

- **Proposed storage additions:** There is currently 35.2 MW/140.2 MWh of proposed utility-scale storage in GMP's territory in the Northern Area and 50.2 MW/ 200.2 MWh of proposed storage in GMP's territory in the Northwestern Area. Because storage can be implemented relatively quickly, GMP's queue does not typically include projects on the 10-year horizon. Therefore, it is reasonable to consider that interconnected storage in 10 years will be much greater than the sum of currently proposed projects. These additions increase operational flexibility and provide greater margin of error for dispatching storage to shift peaks away from the evening and early morning hours.
- **Growth in behind-the-meter storage:** Continued adoption of behind-the-meter storage for resiliency purposes is expected to further increase the amount of load that GMP can shift during peak hours.
- **ISO-NE Planning Procedure 7 revisions** will allow for winter planning ratings to be based on a lower ambient air rating than today, increasing winter ampacities on subtransmission and transmission. Further, FERC Order 881 calls for real-time operational ratings to be based on ambient temperatures. For winter concerns, like in the Northern area, this will result in further margins since peak loads only occur on the coldest days.

The 2027 Long Range Transmission Plan will feature the following assumptions that reflect the work performed by VELCO, GMP, and the other DUs as part of the 2024 LRTP cycle and the 2024 NTA analysis:

- An updated forecast that shows a significantly lower projection of EV adoption across the state pending the removal of federal EV incentives.
- An updated forecast that reduces the load contributions of heat pumps in the winter months as a result of the findings of the Ridgeline Heat Pump Study conducted for the Department of Public Service.
- Inclusion of existing TOU EV charging programs as part of the base-line load shape, applied to fully electric EVs at the enrollment rates that are consistent with enrollment rates GMP projected in its 2024 IRP and the 2024 NTA analysis.
- Inclusion of peak-shifting storage, flexible load management, and event-based EV programs as part of the LRTP study process. This effort captures the resources that are already available on the system today and that are used to reduce transmission costs for customers on the distribution system.

Appendix 1/1: Project Specific Action Plan for Northern and Northwest Areas

Northern and Northwestern Vermont Project Specific Action Plans		
Lead utility **Affected utilities**	GMP GMP, VEC, BED, Global Foundries, WEC, VPPSA	Date of this plan: January 2026
Description of deficiency	The Northern Vermont Reliability concern is the result of load growth, primarily driven by forecasted electrification of the transportation and heating sectors. The *Vermont Road Map* forecast – originally developed in 2023 for the Long Range Transmission Plan - assumes that future EV loads will have uncontrolled profiles, meaning that peak EV loads would overlap with peak base and heating lo ads. The voltage collapse concern arises as the result of an N-1-1 event on the 115 kV system, followed by tripping of multiple subtransmission lines to avoid thermal overloads on the 34.5 kV system. Similarly, the Northwest Vermont Reliability concern is caused by the forecast of high load growth in EVs and heat pumps and therefore can be resolved using the same methodology. There is a low voltage concern (no voltage collapse) following an N-1-1 contingency on the bulk transmission system and subsequent tripping of multiple subtransmission and one 115 kV line to avoid thermal overloads.	
Critical load level / timing of need	The critical load level is 505 MW in the Northern Vermont area, and the *2024 Long Range Plan* shows a potential peak load of 580 MW during some winter peak events. The timing of this concern is Winter 2033 under the *Vermont Road Map*, or VELCO's highest load growth case. The critical load level is 705 MW in the Northwest Vermont Area, and the *2024 Long Range Plan* shows a potential peak load of 785 MW during some summer and winter peak events. The timing of this concern is Summer 2029 under the *Vermont Road Map*, or VELCO's highest load growth case.	
Geographical area	The geographic area for the Northern Vermont area is all of Northern Vermont, bounded by the Plattsburgh, Williston, Granite, and Littleton substations. The geographic region for the Northwestern Vermont area includes the Northern Vermont area and extends south to include the Middlebury and Florence areas. It is bordered electrically by the Plattsburgh, West Rutland, Granite and Littleton substations.	

Transmission solution(s) & study status	The transmission solution proposed for the Northern Area is to add a second transmission line between VELCO's Essex and Williston substations and to replace three 115/34.5 kV transformers (Queen City, Tafts Corners, and Barre). The cost estimate for this project is $153M. Additional analysis is needed to confirm the final upgrade design. The transmission solution proposed for the Northwest Area is to rebuild the Middlebury to West Rutland 115 kV line and to replace the Middlebury 115/46 kV transformer. The cost of this project is $228M. Additional analysis is needed to confirm the final upgrade design.
NTA screening	The deficiencies for both areas screened in for full NTA analysis in the 2024 *Vermont Long-Range Transmission Plan (LRTP)*.
NTA solution(s) & study status	The *2024 Long Range Transmission Plan* identified the load reduction needed in the Northern Study Area as 75 MW in 2033 that grows over time and 80 MW by 2033 in the Northwest Area. However, the VT Roadmap Forecast case does not account for existing EV charging control programs and residential/utility scale storage programs that actively reduce peak loads today. The LRTP assumes an indefinite load reduction is required, however many of the NTA's available today are finite resources. In order to analyze and design a viable NTA solution so that a wider variety of solutions could be compared to the transmission solution, it is crucial to know about both the power (MW) and energy (MWh) reduction needed. Because the energy needs were not understood from the 2024 LRTP, GMP requested that VELCO perform an hour-by-hour energy assessment for 2033 known as an 8760 analysis to determine the critical load level within the study area and therefore the frequency, duration, and depth of any overloads that are expected to occur under the study's assumptions. The time series analysis found that there is a maximum of 75 MW/230 MWh of load reduction needed in the Northern area in 2033, and 80 MW/318 MWh of load reduction in Northwestern Area in 2033. *See figures 1 and 2, for load shapes on the peak days of these areas, respectively.* Following VELCO's 8760 analysis of the Northern and Northwestern Areas, GMP performed additional NTA analyses in coordination with the NTA working group and the VSPC Geographic Targeting Subcommittee to refine the EV charging and storage dispatch assumptions that were used in the 2024 LRTP. **Northern Area:** The first step of this refined analysis was to update EV charging assumptions. VEC, and WEC provided GMP with their expected EV charging control contributions, using data from participation in current EV charging rates. GMP took this information along with the level of control that we expect to have in 2033 and applied a revised charging curve to reflect the appropriate amount of uncontrolled charging and a future managed charging program that pushes the "rebound" period later into the evening. This revised charging curve is based on illustrative revisions to GMP's existing Rate 72 and 74 charging

programs to encourage customers to charge their vehicles later in the night and to spread out the charging rebound effect that managed charging rates and exacerbate. *Figure 3 shows the original and revised EV charging curves*

For EV load management, within GMP's territory it was assumed that a total of 65% of EVs will be under a control program in 2033. The current participation rate is roughly 71% of all EVs in GMP territory. Based on historical data it was assumed that a 2% opt-out rate for managed charging events in the future. Combined with uncontrolled daytime charging, GMP applied a revised EV controlled curve to 50% of vehicles in the Northern and Northwestern Areas to add a layer of conservatism and allow for customer opt-outs, uncontrolled daytime charging, and a decline in adoption rate over time. *Figure 4 shows GMP's adoption rate of managed charging programs over time.*

In the forecast that was developed for the 2024 LRTP, it was projected that there would be 20.1 MW of uncontrolled EV charging load in the Northern Area in 2025 which was forecasted to increase to 92 MW of uncontrolled charging load by 2033. Affected DUs reported what percent of their future charging load they would be able to manage, and these results were included in the development of the revised charging curve assumptions.

With the EV control assumption updated, the needed load reduction dropped from 75 MW/230 MWh to 41.6 MW/101.5 MWh. *Figure 5 shows the impact of EV management on the Northern area load shape.*

GMP next updated the storage dispatch of existing storage available in the Northern Zone. The NTA Working Group made the decision to include only actively interconnected storage resources in the analysis since proposed projects have a degree of uncertainty in their interconnection timeline and power purchase agreement conditions. The Northern Area actively uses the following resources for peak shaving purposes:

Northern Area Active Storage		
	MW	**MWh**
GMP Residential Storage (BTM)	11.7	31.4
GMP Utility-Scale Storage	16.1	45.3
VEC Storage	7.5	30.4
GF Storage	15	60
Total	**50.3 MW**	**167.1 MWh**

Taking round trip efficiency and storage capacity degradation into account, this storage is enough to shift remaining forecasted peak loads later into the evening so that the load level in the Northern Area remains below the critical load level of 505 MW at all hours. With these two inclusions, the need for an NTA is deferred to beyond 10 years. *Figure 6 shows the impact of this portfolio of storage on area loading.*

Northwestern Area:

GMP applied the same methodology from the Northern Area analysis to the Northwest Area. This area has both winter and summer reliability exposure, so the summer exposure was analyzed. The winter exposure is very similar in shape and duration to the Northern Area curves discussed above.

The 2024 LRTP stated a need for an indefinite load reduction of 80 MW, although this was updated in VELCO's time series analysis to a load reduction in the summer of 80 MW/318 MWh without any EV charging controls or storage dispatch included. *See Figure 2.*

Using the same methodology as above, EV charging controls were applied to GMP, VEC, and WEC charging loads. Using the same revised charging curves, the required load reduction decreased to 32 MW/106 MWh. *See figure 7.*

GMP next included active residential and utility scale batteries within the Northwestern Area that are currently being used to reduce monthly peak loads. Including residential storage, utility scale storage, and VEC and GlobalFoundries storage, there is:

Northwestern Area Active Storage		
	MW	**MWh**
GMP Residential Storage (BTM)	15.9	42.7
GMP Utility-Scale Storage	24.1	72.9
VEC Storage	7.5	30.4
GF Storage	15	60
Total	**62.5 MW**	**206.0 MWh**

Taking a conservative round trip efficiency of 85% into account, the available active storage in the Northwest Area is sufficient to maintain loads below the critical load level of 705 MW and defer the need for a transmission solution to beyond 10 years. *Figure 8 shows the impact of the portfolio of active storage on Northwest Area loading.*

Other Factors Affecting Deferral Timeline:

The NTA analysis discussion identified several additional assumptions that are expected to evolve in the upcoming *2027 Long Range Plan* and may affect the deferral timeline. These uncertainties include:

	• Revised EV load projects: The updated 2026 load forecast reflects a significant reduction in near-term EV load growth, with the adoption rate of EVs shifting until later in the 2030s. • Revised heat pump impacts: The updated 2026 forecast also shows a large reduction in projected heat pump coincident peak loads, particularly in areas with natural gas service like the Champlain Valley. • Proposed storage additions: There is 35.2 MW/140.2 MWh of proposed utility-scale storage in GMP's territory in the Northern Area and 50.2 MW/ 200.2 MWh of proposed storage in GMP's territory in the Northwestern Area. These additions increase operational flexibility and provide greater margin of error for dispatching storage to shift peaks away from the evening and early morning hours. • Growth in behind-the-meter storage: Continued adoption of behind-the-meter storage for resiliency purposes is expected to further increase the amount of load that GMP can shift during peak hours. • ISO-NE Planning Procedure 7 revisions will allow for winter planning ratings to be based on a lower ambient air rating than today, likely increasing winter ampacities on subtransmission and transmission. Further, FERC Order 881 calls for real-time operational ratings to be based on ambient temperatures. For winter concerns, like in the Northern area, this will result in further margins since peak loads only occur on the coldest days.
NTA/TA hybrid solution(s) & study status	There is no need for a hybrid transmission solution since the exposure can be managed by leveraging existing storage and EV resources, as well managing projected future EV charging load at a rate consistent with GMP's forecasted capabilities.
Solution selection	As a result of the analysis described above, GMP and the NTA Working Group have concluded that the Northern and Northwest deficiencies are deferred through the above analysis. There is no need to plan and build a traditional transmission solution for the Northern and Northwestern Areas at this time for this reason. By applying EV charging management at rates that exist today to future/revised EV charging loads and derating them at an amount to allow for opt-outs and drop in enrollment over time, the load reduction needs are less in amplitude and duration in both study areas. Further, accounting for peak shaving behavior of residential and utility-scale storage demonstrates that peak loads can be maintained below the respective critical load levels while preserving sufficient evening capacity to fully recharge storage and pre-position it for the next peak event. Looking ahead to the next three-year long range planning cycle, the assumptions refined as part of this NTA study should be tracked by all affected DUs. Continued tracking will support the most accurate representation of all flexible resources on the Vermont distribution

	system and ensure that resources actively used to shape peak loads and reduce customer costs are appropriately reflected in future planning analyses.
Cost allocation	N/A
Public outreach	Both VELCO and GMP conducted routine public updates through the VSPC. The NTA analysis was discussed at the following meeting times: • 1/22/2025 – VSPC Quarterly Meeting • 4/30/2025 – VSPC Quarterly Meeting • 7/09/2025 – Geographic Targeting Subcommittee Meeting • 7/16/2025 – VSPC Quarterly Meeting • 9/30/2025 – NTA Working Group Meeting • 10/23/2025 – NTA Working Group Meeting • 10/27/2025 – Geographic Targeting Subcommittee Meeting • 10/29/2025 – VSPC Quarterly Meeting • 11/6/2025 – NTA Working Group Meeting • 11/13/2025 – Geographic Targeting Subcommittee Meeting All publicly available materials have been uploaded to VSPC website: https://www.vermontspc.com/subcommittees Additional public engagement has been conducted through PUC investigation into LRTP: Case No. 24-3351-INV.
Implementation	The need for transmission upgrades in the Northern and Northwestern Areas is deferred by updating the load shapes to reflect the impacts of existing EV charging management and battery storage programs. The next Long Range Plan should consider these active and interconnected resources as part of the system load before conclusions about whether transmission solutions are needed are drawn. The distribution utilities can support this effort through tracking and sharing the following metrics: • **EV charging management enrollment rates,** expressed as a percentage of vehicles within each service territory. • **Customer Opt-out rates** for those enrolled in EV charging management programs. • **Coincident peak EV load reductions,** quantified as the megawatts of EV charging reduced during system peak hours because of management programs. • Planned program refinements, including changes to Time-Of-Use windows, event frequency, event duration, etc.) • Behind-the-meter (BTM) and utility scale storage capacity, reported in MW/MWh at each substation or bus, along with associated control strategies and dispatch methodologies.

	• Available flexible load capacity, including C&I customers, reported in MW/MWh at each substation and operational strategy used to call these events. Further work is required to identify and track performance-based metrics that capture the reliability and effectiveness of peak-shifting resources such as storage dispatch, day-ahead EV charging events, and flexible load management (FLM) programs. VELCO can support this effort by identifying the data needs of their planners and system operators to build confidence in the performance of BTM peak-shifting resources and their impacts on bulk transmission flows.
Factors that may affect project timing	N/A, since there is no build out needed.

Figures:

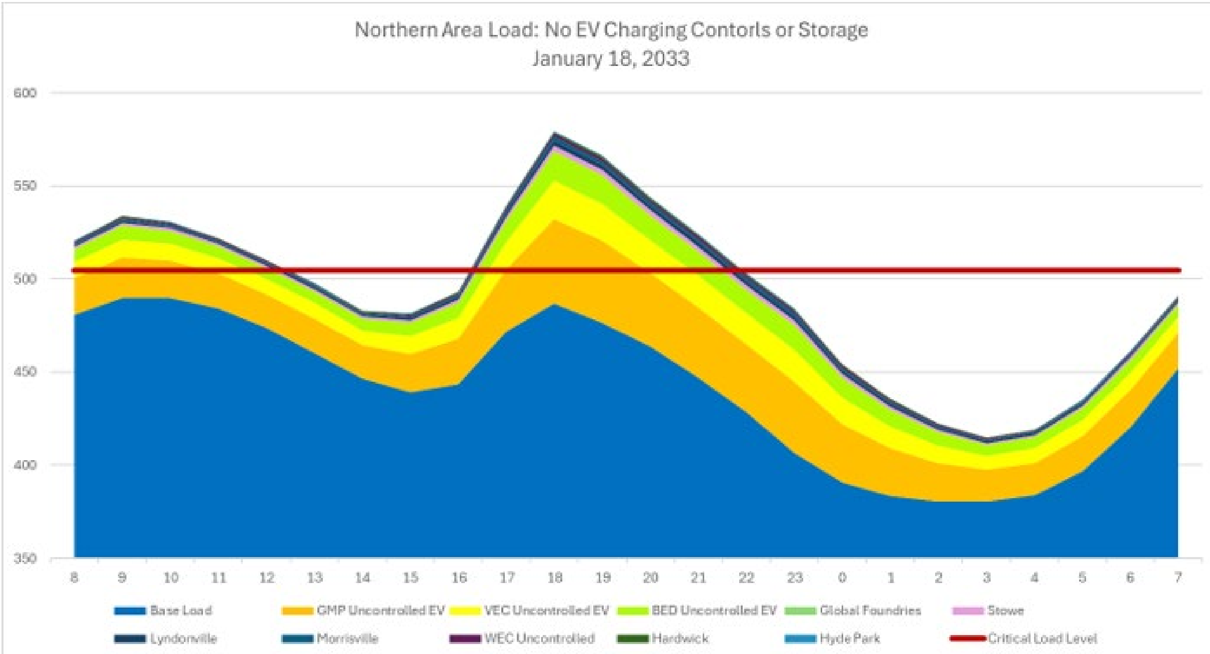

FIGURE 1: NORTHERN VERMONT AREA LOADS ON THE PEAK WINTER DAY IN 2033. THERE ARE NO EV CONTROLS OR STORAGE APPLIED IN THIS GRAPH, CONSISTENT WITH THE ORIGINAL ASSUMPTIONS IN THE 2024 LONG RANGE TRANSMISSION PLAN

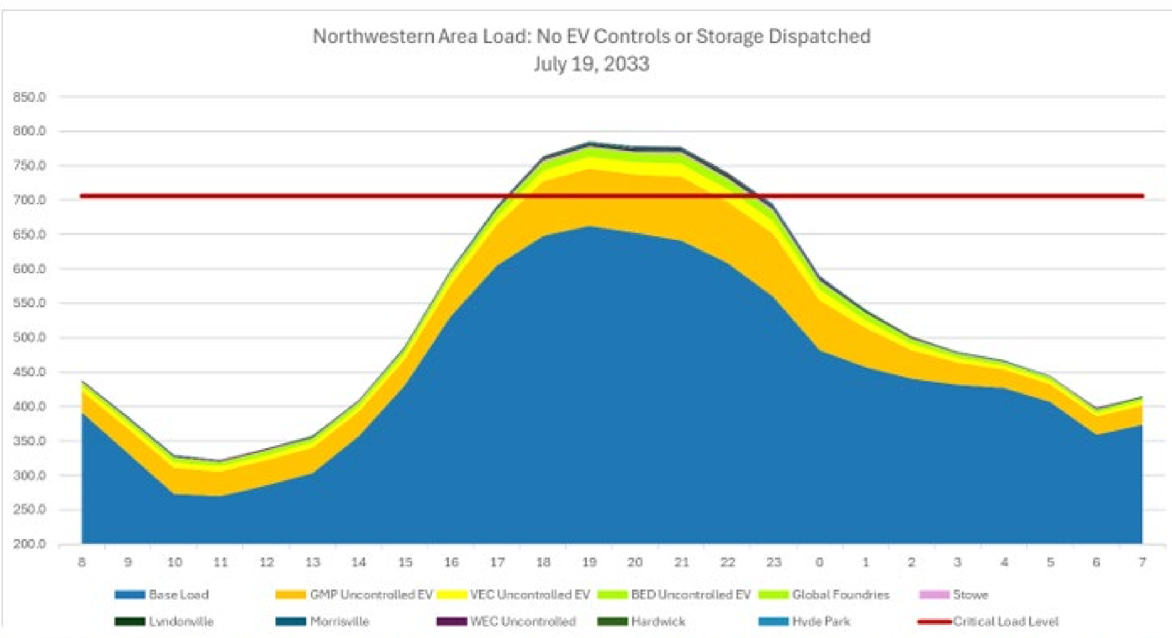

FIGURE 2: NORTHWESTERN VERMONT AREA LOADS ON THE PEAK SUMMER DAY IN 2033. THERE ARE NO EV CONTROLS OR STORAGE APPLIED IN THIS GRAPH, CONSISTENT WITH THE ORIGINAL ASSUMPTIONS MADE IN THE 2024 LONG RANGE TRANSMISSION PLAN.

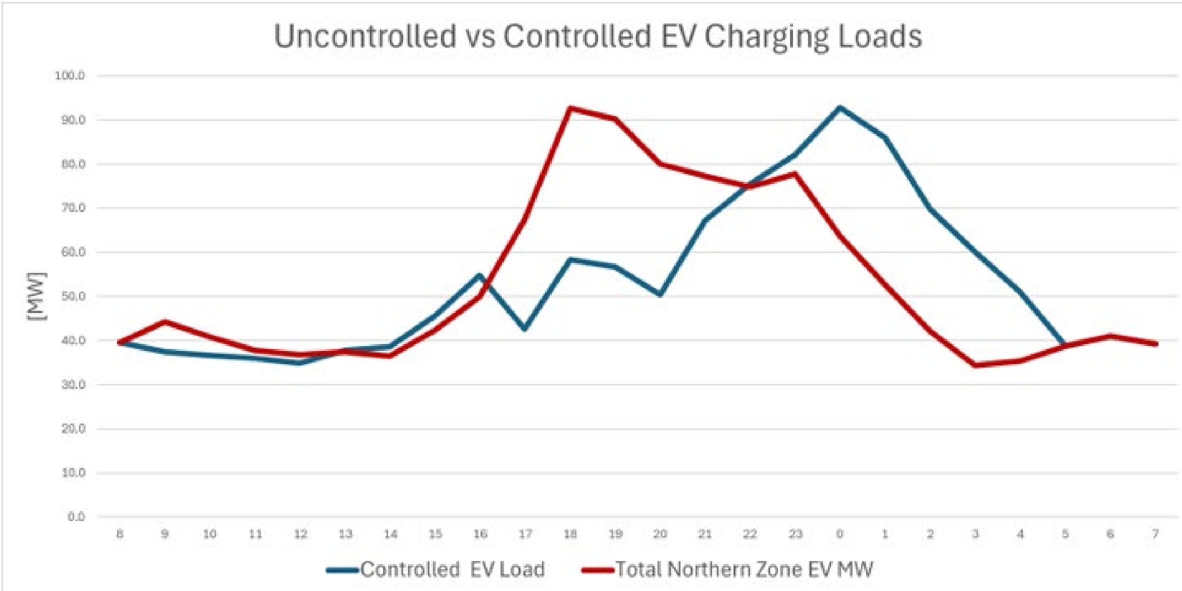

FIGURE 3: ORIGINAL UNCONTROLLED EV CHARGING CURVE USED IN THE LONG RANGE PLAN (RED) VS. THE REVISED EV CHARGING CURVE BASED ON REVISED TOU AND EVENT-BASED PROGRAMS WITH ADOPTION LEVELS AT 50% LOAD REDUCTION RATES FOR GMP AND VEC, AND 33% FOR WEC.

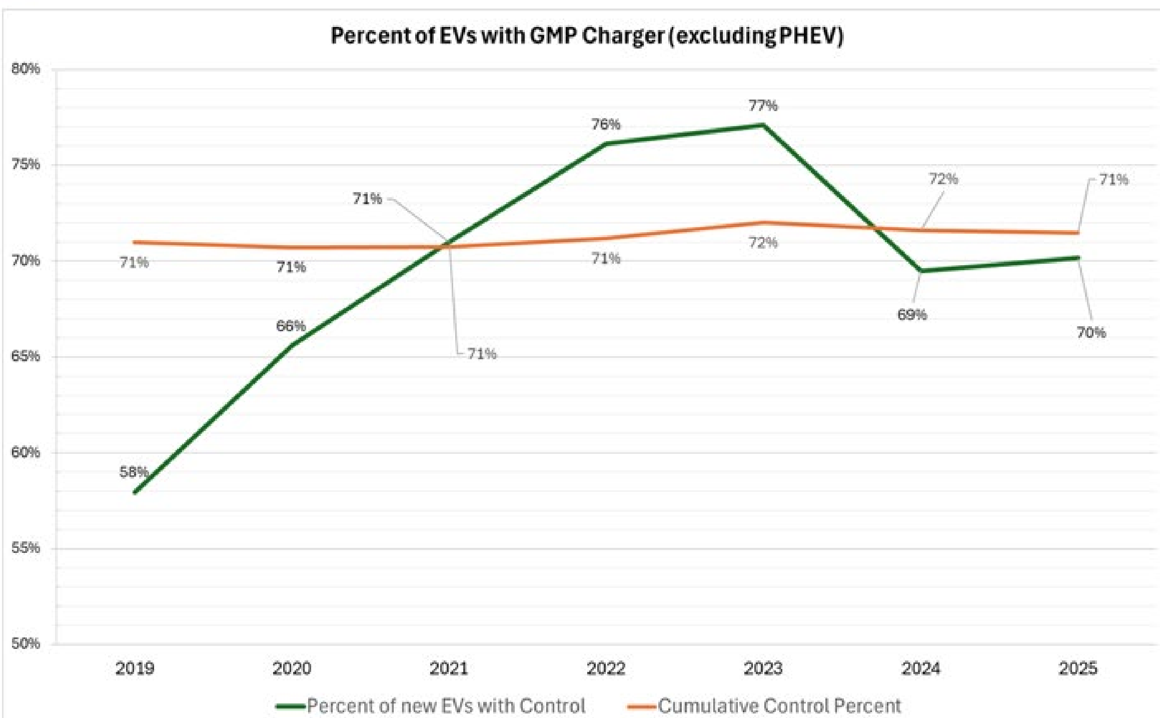

FIGURE 4: GMP'S EV CHARGING MANAGEMENT ADOPTION RATES FOR FULLY ELECTRIC VEHICLES OVER TIME.

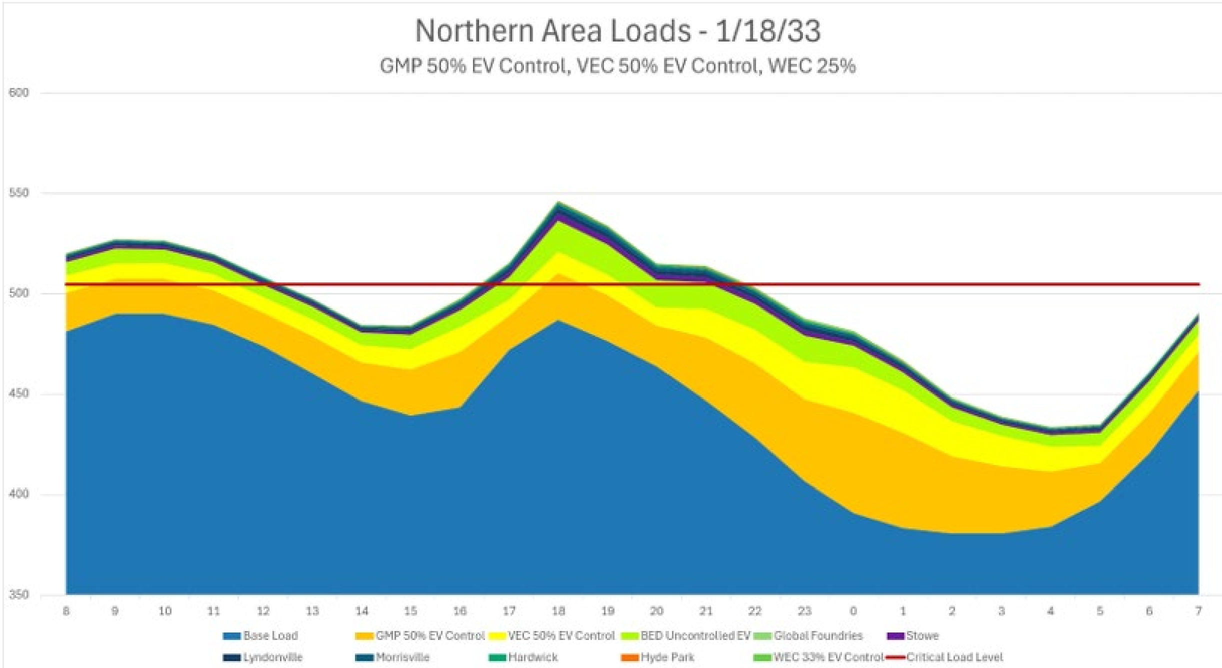

FIGURE 5: NORTHERN AREA LOADS FOLLOWING EV CONTROLS AND TOU PROGRAMS.

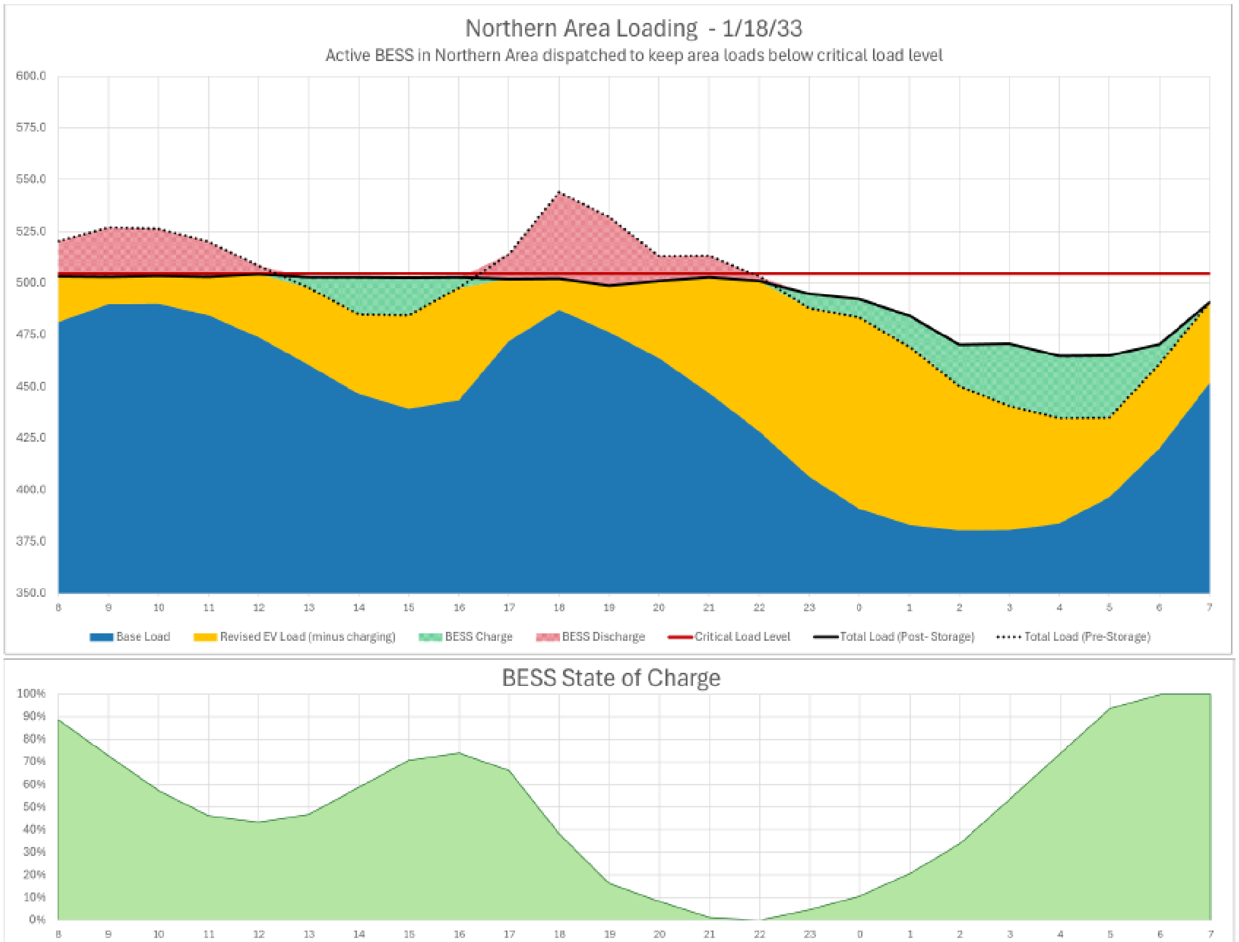

FIGURE 6: NORTHERN AREA LOAD WITH ACTIVE STORAGE USED TO SHIFT PEAK LOADS. THE SOLID BLACK LINE SHOWS THE FINAL NET LOAD FOLLOWING STORAGE CHARGE/DISCHARGE. THE RED AREA SHOWS LOAD THAT WAS REDUCED BY THE BESS, THEGREEN AREA SHOWS NEW CHARGING LOAD.

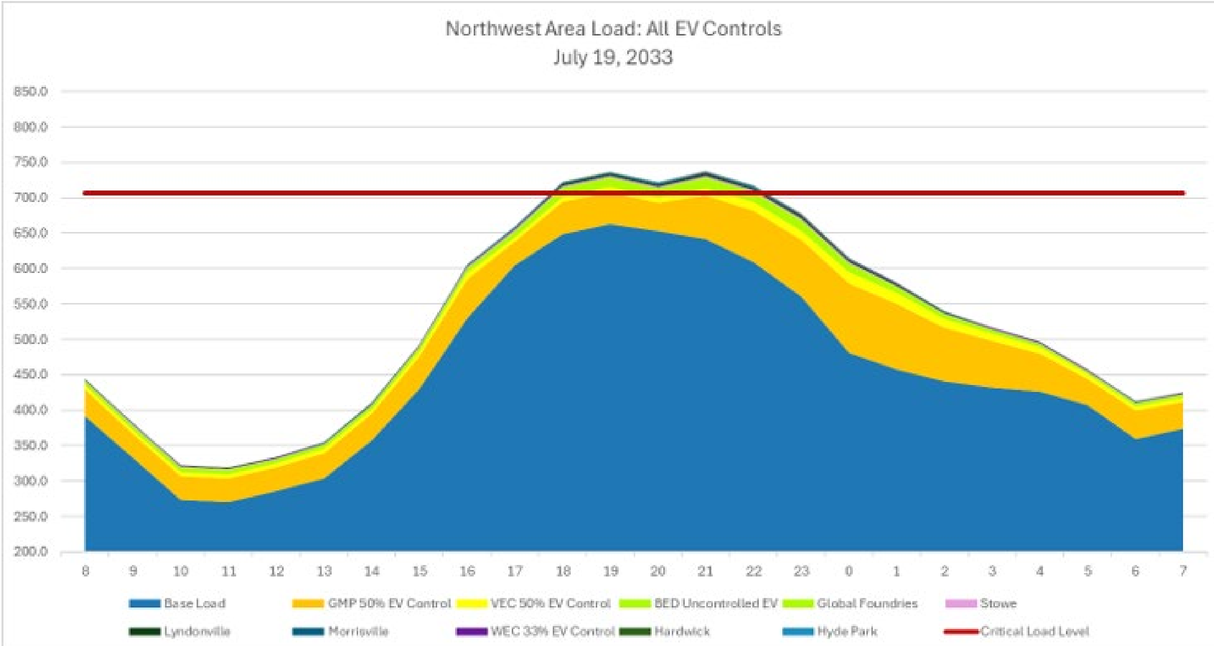

FIGURE 7: NORTHWESTERN AREA LOAD WITH ALL EV CHARGING CONTROLS APPLIED.

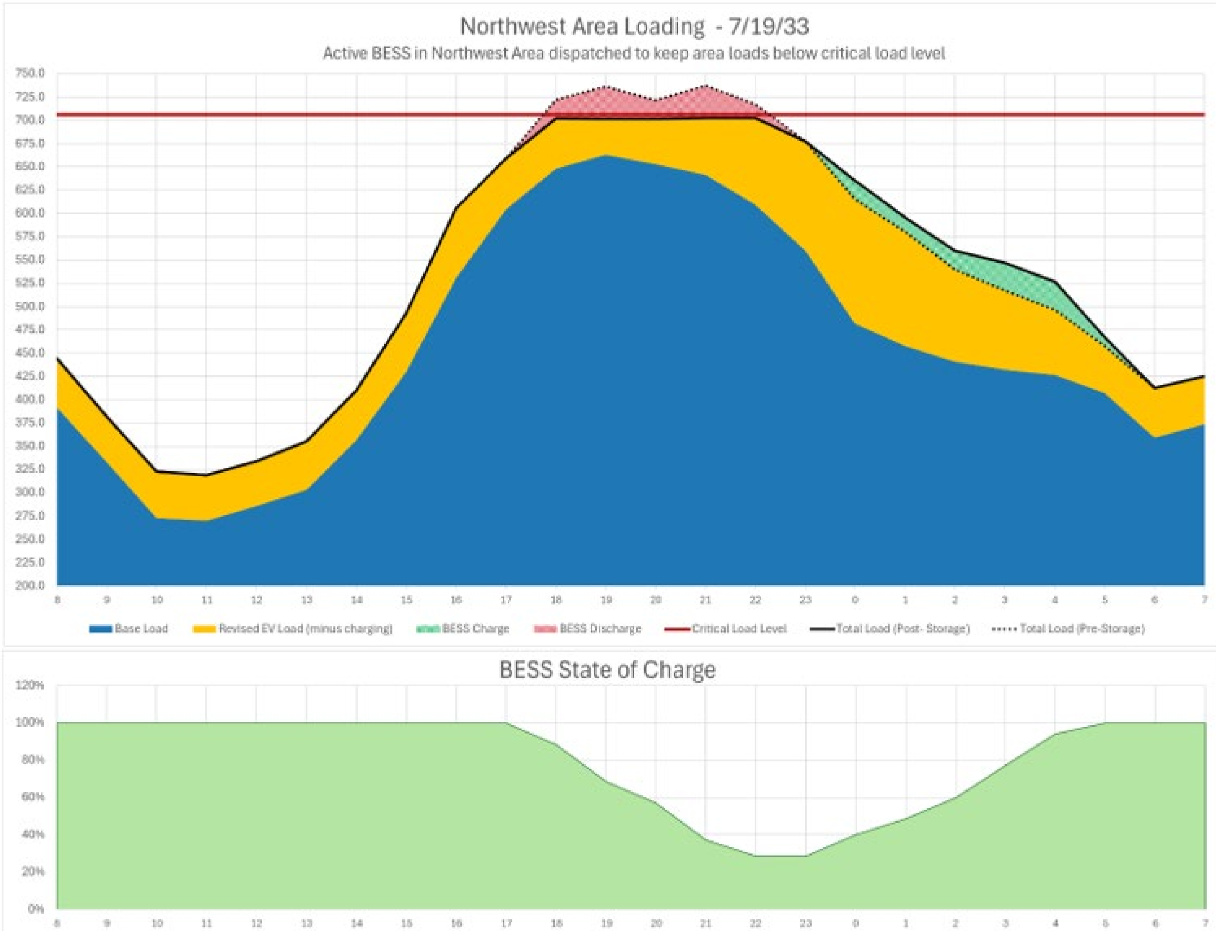

Figure 8: Northwest area load with active storage dispatched to keep loads below critical load level.