Regional Electric Peak Load Forecasts for Maine: Implications of Electrification and ISO-NE CELT Forecasts

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EXECUTIVE SUMMARY

Synapse Energy Economics, Inc. (Synapse) prepared this report for the Maine Office of the Public Advocate (OPA) to develop independent summer and winter electric peak load forecasts for Maine through 2033 and to assess how emerging load drivers—particularly building and transportation electrification—are expected to reshape state and regional peak demand patterns. The analysis is intended to support OPA's review of utility system planning and future grid investment needs across Maine.

Study Scope and Analytical Approach

This study develops 90/10 peak load forecasts for Maine's three ISO New England (ISO-NE) planning subareas—Northeastern Maine (NME), Central and Western Maine (CME), and Southeastern Maine (SME, including Portland)—for 2024–2033. Total peak demand is broken into the following components:

- Conventional (base) electric load, inclusive of embedded energy efficiency
- Heating electrification, including heat pumps for space and water heating
- Transportation electrification, including electric light-duty vehicles and electric medium- and heavy-duty vehicles
- Behind-the-meter solar photovoltaics, which reduces net load
- Demand response and storage, based on cleared capacity resources

Synapse relies on ISO-NE's 2025 Capacity, Energy, Loads, and Transmission (CELT) forecast for conventional loads, while independently modeling region-specific hourly peak impacts from electrification and distributed resources. We compare our results to ISO-NE's 2024 and 2025 CELT forecasts to identify differences in assumptions, methods, and planning implications.

Key Findings

1. Maine Is Already Transitioning to a Winter-Peaking System

Maine's electric system is in the midst of a structural transition from summer-peaking to winter-peaking demand, driven primarily by heating electrification.

- NME and CME are already winter peaking, with winter net peaks exceeding summer peaks today.
- SME is projected to become winter-peaking around 2028, as heating electrification accelerates.

- By the end of the study period, winter peak demand exceeds summer peak demand in all three regions, with winter growth far outpacing summer growth.

Figure ES-1, Figure ES-2, and Figure ES-3 illustrate these trends clearly by region. Across all three subareas, summer peak demand grows modestly through 2033, while winter peak demand grows rapidly—particularly after the mid-2020s—reflecting the increasing contribution of electric space heating.

- Summer peak growth ranges from approximately 10–17 percent by 2033, depending on region and scenario.
- Winter peak growth is substantially larger, ranging from 30–70 percent under the Medium scenario, with even higher growth under the High scenario.

These figures demonstrate that future system planning challenges in Maine are increasingly driven by winter peak conditions rather than traditional summer peaks.

Figure ES-1. Winter and summer peak loads by scenario through 2033, Northern Maine

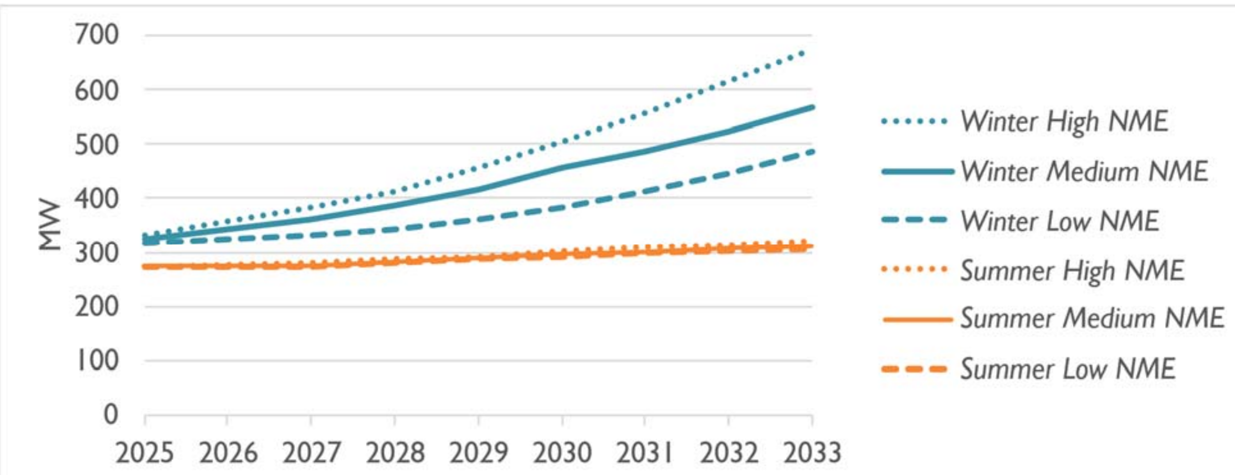


Figure ES-2. Winter and summer peak loads by scenario through 2033, Central Maine

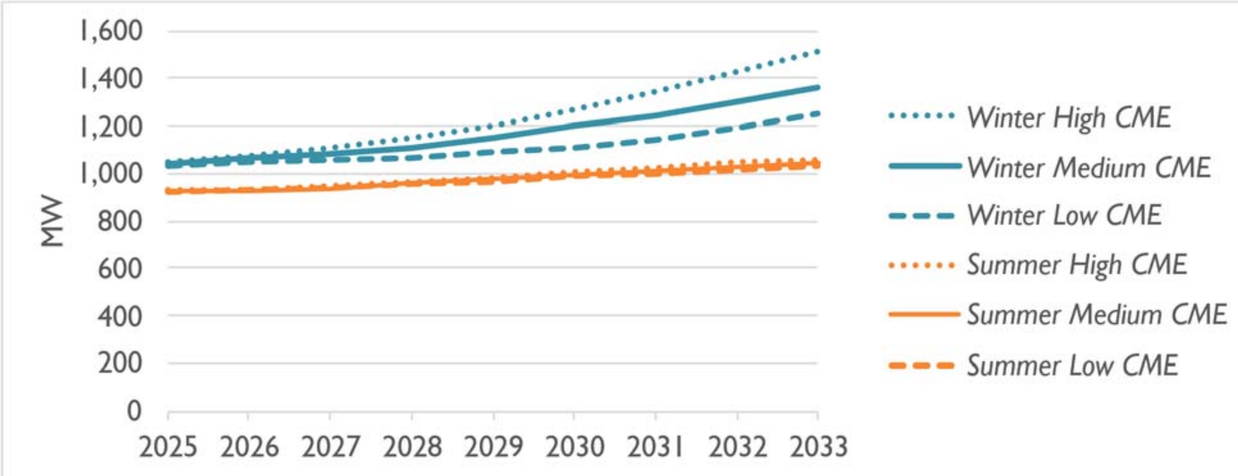
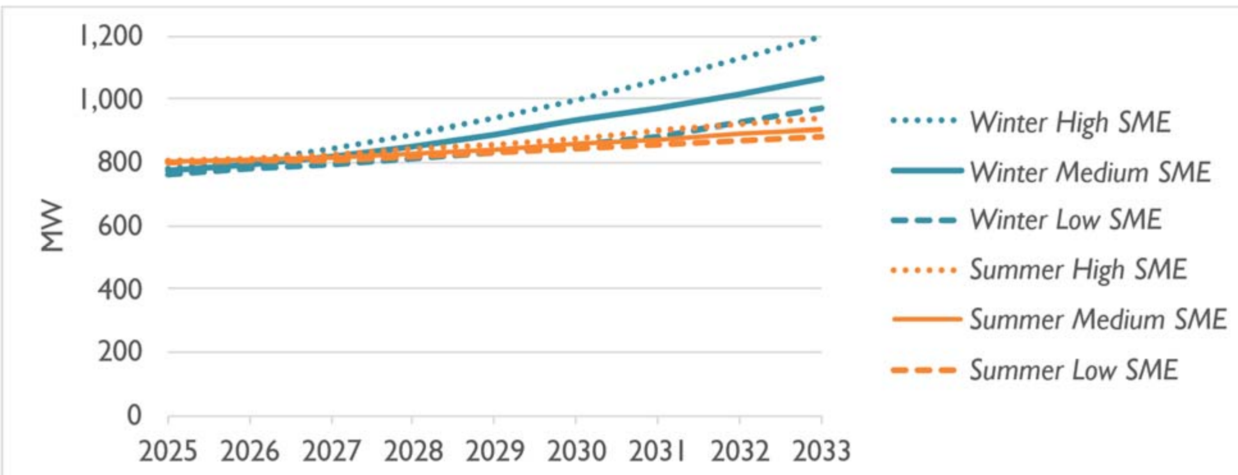


Figure ES-3. Winter and summer peak loads by scenario through 2033, Southeastern Maine



2. Heating Electrification Is the Dominant Driver of Winter Peak Growth

Heating electrification is the primary contributor to future peak load growth in all regions and overwhelmingly dominates winter peak impacts.

Figure ES-4 and Figure ES-5 disaggregate the projected 2033 peak loads by load component and region, making clear which factors are driving growth:

- Under the Medium scenario, heating electrification contributes approximately 964 MW of additional winter peak load statewide by 2033.
- Residential space heating represents the largest share of heating-related peak demand, followed by commercial space heating.
- Electric water heating contributes a relatively small share—on the order of 2 to 3 percent of total winter peak demand.

Regional impacts vary significantly. In NME, colder temperatures lead to higher per-unit heat pump demand, resulting in proportionally larger winter peak increases relative to summer. CME and SME also experience substantial winter growth, but with different mixes of conventional load growth and electrification impacts.

These results underscore that winter system adequacy, not summer peak management, will be the primary driver of future transmission and distribution investment needs in Maine.

Figure ES-4. Winter coincident peak load in 2033, by scenario and region

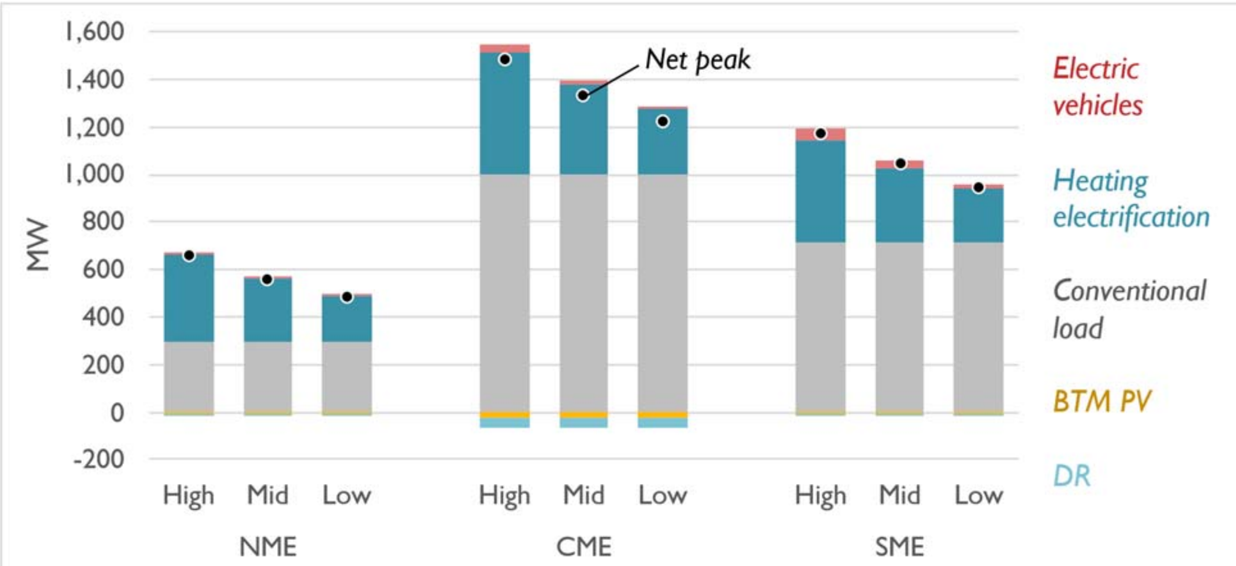
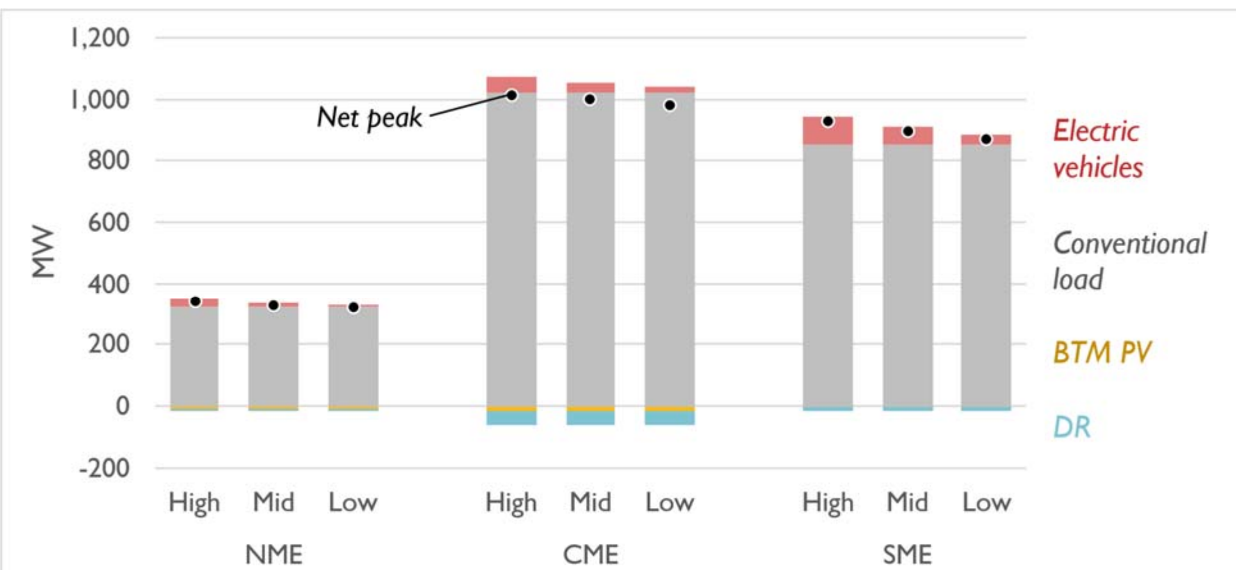


Figure ES-5. Summer coincident peak load in 2033, by scenario and region



3. Transportation Electrification Contributes to Peak Growth but Is Secondary and Manageable

Transportation electrification increases both summer and winter peak demand, but its contribution is modest compared to heating electrification.

- By 2033, electric vehicle (EV) charging contributes approximately 95–105 MW to winter peaks and 160–180 MW to summer peaks statewide in the absence of managed charging.
- Home charging dominates EV peak impacts, particularly in the evening.
- Medium- and heavy-duty EVs contribute relatively little to coincident system peaks.

Figure ES-4 and Figure ES-5 show that EV charging accounts for only a small share of total winter peak demand (generally a few percent), even in high-adoption scenarios. Managed charging programs have the potential to reduce EV peak impacts by between 10 and 72 percent, depending on participation rates and program design.

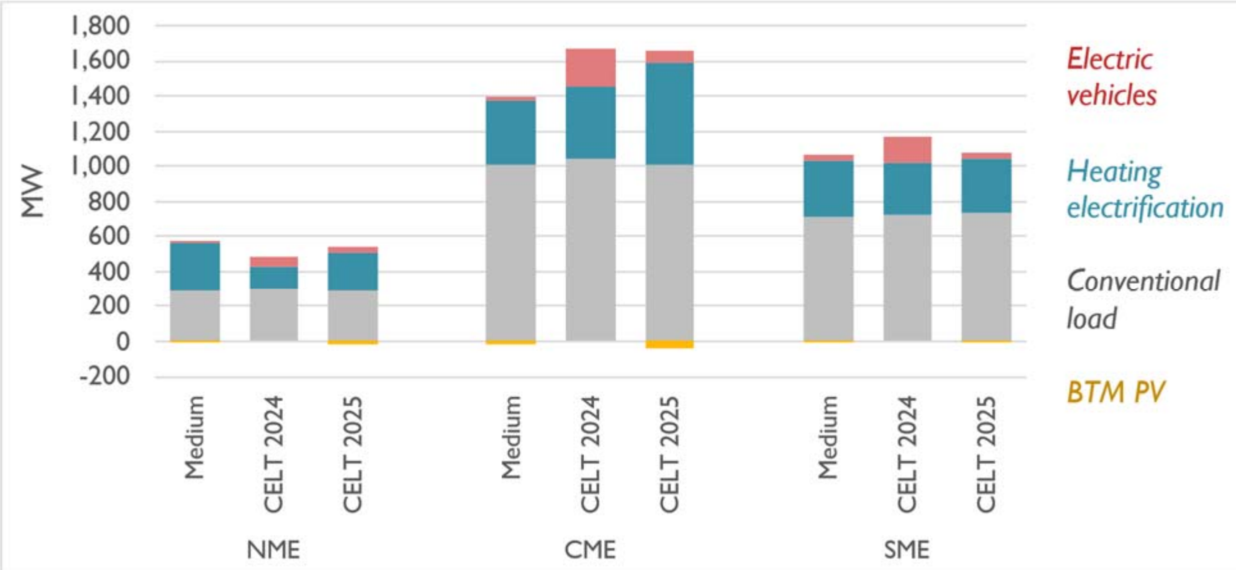
As a result, while EV adoption is an important load growth factor, it is not the primary driver of future peak needs, especially in winter.

4. CELT Comparisons Reveal Important Regional and Methodological Differences

Figure ES-6 compares Synapse's Medium-scenario 2033 winter peak forecasts with ISO-NE's 2024 and 2025 CELT forecasts by region and load component. Several key findings emerge:

- Overall, the 2025 CELT projects lower summer and winter peak loads than the 2024 CELT, except for winter peak loads in NME.
- In summer, Synapse's estimates are generally very close to or slightly higher than the 2025 CELT, and consistently lower than the 2024 CELT.
- In winter—when peak loads are substantially higher than summer peaks by 2033—distinct regional differences emerge:
    - **NME:** Synapse's Medium scenario and the 2025 CELT are close, with Synapse's Medium scenario slightly higher. Both are noticeably higher than the 2024 CELT.
    - **CME:** The 2024 and 2025 CELT forecasts are very close to each other and substantially higher than Synapse's estimate, but for different reasons. The 2024 CELT projects considerably higher EV loads—likely overstated due to inflated EV stock forecasts—while the 2025 CELT projects considerably higher heat pump loads, in part because it relies on outdated assumptions about heat pump efficiency.
    - **SME:** Synapse's Medium scenario and the 2025 CELT are very close and substantially lower than the 2024 CELT.

Figure ES-6. Regional winter peak load by component in 2033 under Medium scenario, with comparison to ISO-NE CELT 2024 and 2025



These findings have direct planning implications. Utilities such as Central Maine Power (CMP), which serve SME and rely on the 2024 CELT in their planning studies (e.g., CMP's 10-year Greater Portland area study), are likely overestimating future regional peak loads, increasing the risk of overinvestment in grid infrastructure. By contrast, utilities such as Versant, which serve NME and rely on the 2024 CELT, may be underestimating future peak loads in colder regions of the state.

5. Regional Granularity and Updated Assumptions Matter

A key takeaway from this analysis is that CELT estimates vary meaningfully by region, and the differences between Synapse's forecasts and CELT forecasts are also region-specific. In particular:

- The 2024 CELT did not fully capture regional weather variation, contributing to understated winter peak projections in NME and overstated projections in other regions.
- Updates to ISO-NE's EV adoption methodology between the 2024 and 2025 CELT materially reduced projected EV peak loads, highlighting the sensitivity of results to modeling assumptions.
- ISO-NE has not yet incorporated results from the most recent heat pump performance evaluation in Maine, which found higher efficiencies at cold temperatures than those assumed in the CELT. This contributes to higher projected heat pump peak loads in colder regions.

More broadly, all forecasts, including Synapse's and both CELT forecasts, do not reflect the expiration of federal EV tax credits. As a result, both Synapse's forecasts and the 2025 CELT may modestly overestimate future EV peak demand, suggesting that future updates should revisit these assumptions.

1. INTRODUCTION AND BACKGROUND

Synapse Energy Economics, Inc. (Synapse) was hired by the Maine Office of the Public Advocate (OPA) to develop summer and winter electric peak load forecasts for Maine to support OPA's assessment of future grid investment needs. To develop regional peak load forecasts within the state, we examined and integrated forecasts for different load components, namely conventional loads, space and water heating electrification, transportation electrification (i.e., electric vehicle (EV) charging), behind-the-meter (BTM) solar photovoltaics (PV), demand response/storage, and energy efficiency (EE).

We developed load forecasts for the state's three subareas for the 10-year period from 2024 through 2033. This timeframe aligns with ISO New England's (ISO-NE) 2024 *Capacity, Energy, Loads, and Transmission* (CELT) reports.[1] Through the CELT, ISO-NE annually produces region-wide energy and peak load forecasts by state and subarea. The CELT forecast serves as ISO-NE's core planning dataset, providing 10-year projections of regional and state-level electric energy use and seasonal peak demand, along with associated capacity and transmission information. These forecasts are used to determine regional resource adequacy requirements, assess system reliability and performance, and inform transmission planning decisions.[2]

During the latter part of our load forecasting project for Maine OPA, ISO-NE published the 2025 CELT. The 2025 CELT includes projections for four load components: base (conventional) load, BTM PV, heating electrification (i.e., heat pumps), and transportation electrification (i.e., EV charging).[3] The CELT combines these individual components to produce both gross and net load forecasts.[4]

ISO-NE continually refines the methods and assumptions when developing the load forecasts each year. Recent updates include capturing the effects of new managed charging programs,[5] expanded accounting

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1 ISO-NE. 2025. "CELT Reports." *Plans and Studies.* Available at: https://www.iso-ne.com/system-planning/system-plans-studies/celt.

2 ISO-NE. 2025. "Load Forecast." *System Forecasting.* Available at: https://www.iso-ne.com/system-planning/system-forecasting/load-forecast.

3 Previous CELT forecasts also included forecasts for EE. As of the 2025 CELT, EE impacts are included in the base load forecast.

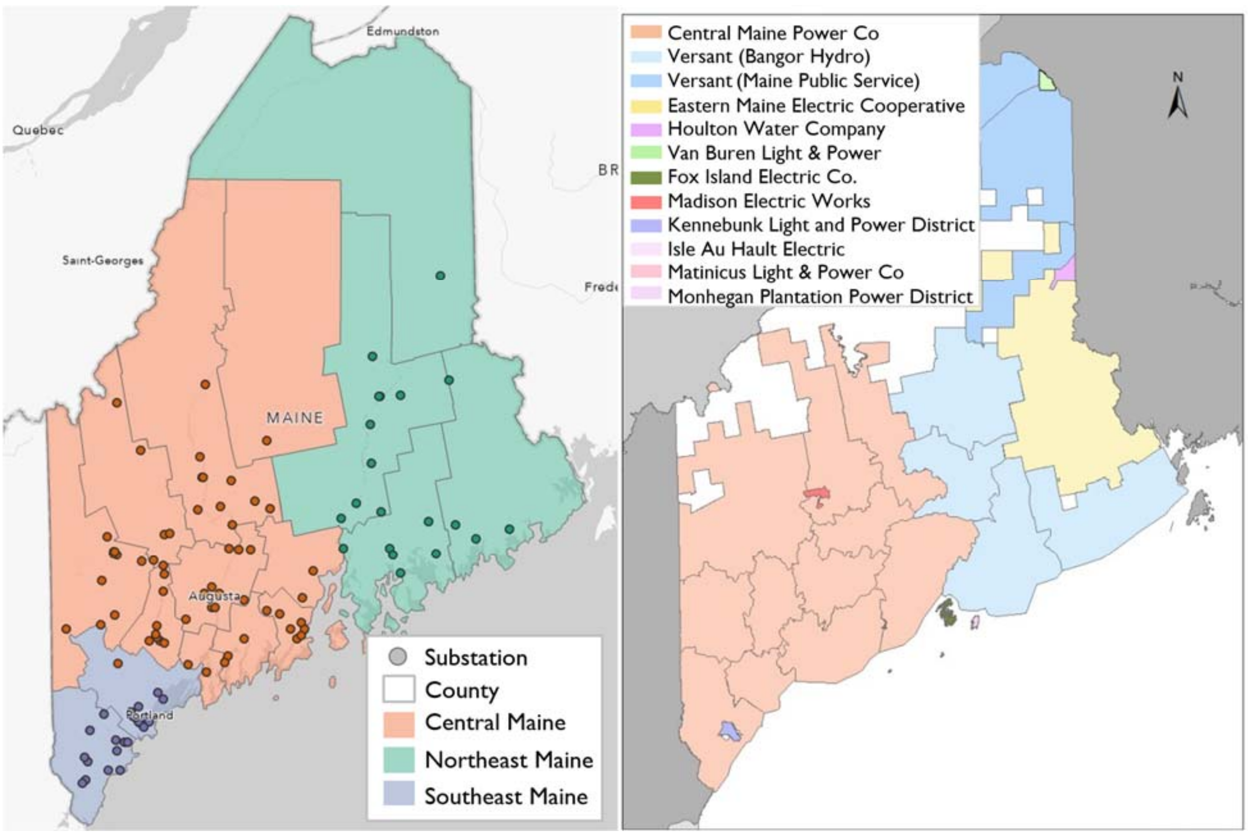
4 Gross load is the base load plus transportation and heating electrification, while net load reflects demand after reductions from EE and BTM PV.

5 ISO Newswire. 2024. "New England's electricity use to increase steadily over next decade, according to 2024 CELT Report." May 1. https://isonewswire.com/2024/05/01/new-englands-electricity-use-to-increase-steadily-over-next-decade-according-to-2024-celt-report/

of distributed energy resources (BTM PV)[6], and implementation of more complex hourly demand modeling, including incorporating EE into conventional load forecasts.

The CELT forecasts are developed at the load zone level for ISO-NE's eight load zones and are also disaggregated across 13 system planning subareas.[7] In Maine, there are three subareas: Northeastern Maine (NME), Central Maine (CME), and Southeastern Maine (SME). We used substation zone data to disaggregate the three ISO-NE load zones in Maine (see Figure).

Figure 1. Visualization of county-zone assignments (left) and utility service areas in Maine (right)



Source: (a) ISO-NE. 2024. PNode Table for new Power System Model Release. https://www.iso-ne.com/markets-operations/settlements/pricing-node-tables. (b) Maine OPA. 2022. Electric Service Area Map. https://www.maine.gov/meopa/sites/maine.gov.meopa/files/inline-files/2022_Electric_Service_Area.pdf

ISO-NE develops gross peak load forecasts for 90/10 and 50/50 load conditions. 90/10 load refers to the load level that has a 10 percent probability of being exceeded due to weather conditions in a given year,

6 ISO Newswire. 2025. "ISO-NE expands accounting forecasting of distributed energy resources." May 27. https://isonewswire.com/2025/05/27/iso-ne-expands-accounting-forecasting-of-distributed-energy-resources/

7 ISO New England. 2025. "Maps and Diagrams" https://www.iso-ne.com/about/key-stats/maps-and-diagrams/#system-planning-subareas

based on the load modeling.[8] Similarly, the 50/50 load level refers to peak demand with a 50 percent change of being exceeded in a given year. We developed our forecasts for 90/10 load conditions, using temperature data corresponding to ISO-NE's 90/10 loads.[9]

Our primary scope was to conduct a detailed review of the 2024 CELT and develop independent load forecasts. While the 2025 CELT became available during the course of our project, our review of that forecast is limited to a high-level assessment, as it was not included in the original scope of work. Nevertheless, where appropriate, we incorporate the 2025 CELT results and compare them with our own forecasts. For our conventional load forecasts, we rely on the 2025 CELT.

In this report, we first examine and develop peak load forecasts for conventional loads. We then describe the methods and assumptions used to develop resource-specific load forecasts (e.g., heating and transportation electrification, BTM PV). We present results for these resource-specific forecasts and provide a comparison to the 2024 and 2025 CELT. Finally, we aggregate the resource-specific and conventional load forecasts to produce total statewide and subarea load forecasts for Maine and compare these results with ISO-NE's CELT forecasts.

2. ISO-NE's 2025 CELT and Conventional Load Forecast

This section summarizes our approach to developing peak load forecasts for conventional loads, including hourly peak loads, over the next nine years and presents the results of our analysis. Conventional load refers to end-use loads primarily driven by economic activity, new construction, population growth, and weather combined with embedded load impacts from EE. ISO-NE refers to this category as "base" load. These loads exclude the impacts of heating and transportation electrification, as well as distributed energy resources (DERs) such as on-site, BTM PV systems and batteries.

Overall load forecasting approach

To develop peak load forecasts, we divided the load forecast components into two large categories: (a) conventional electric loads and (b) non-conventional electric loads including electrification loads and DERs.

For the first category (conventional electric load), we developed our peak load forecasts primarily based on ISO New England's (or ISO-NE) summer and winter peak load forecasts with appropriate adjustments

[8] ISO New England. 2023. *Transmission Planning Technical Guide Appendix J: Load Modeling Guide*. *Revision 3.0*. Page 7. Available at: https://www.iso-ne.com/static-assets/documents/2023/03/transmission_planning_technical_guide_app_j_load_modeling.pdf.

[9] Note the 90/10 load condition is different than 90/10 weather conditions. 90/10 weather conditions refer to the severity of the weather and may not correspond to the 90/10 load experienced by the electric system. We used the weather ISO-NE assumed under 90/10 load conditions, not the 90/10 weather conditions.

to hourly peak load shapes, considering extreme weather conditions. This process involves the following few steps:

(a) First, we reviewed ISO-NE's load forecasts in the 2025 CELT for the three subareas in the state—NME, CME, and SME—and removed all non-conventional load components;[10]

(b) Second, we identified winter and summer peak days and their corresponding hourly loads based on historical weather and load data, and adjusted the historical peak loads to account for extreme weather conditions; and

(c) Finally, we estimated hourly winter and summer peak loads for three subareas for the next 9 years, using the load shapes developed in the previous step and ISO-NE's peak load forecasts

This section describes the above-mentioned steps in detail.

For the second load forecast category (non-conventional electric loads), we developed hourly peak load impacts separately for several non-traditional load components, including heating electrification (or heat pumps), transportation electrification (or EVs), BTM PV, and demand response. We summarize our methodology and peak load estimates for these components under section 3.2 and 3.3.

Review of ISO-NE's load forecasts

ISO-NE's load forecasts for Maine subareas

ISO-NE's forecast is an additive forecast with four components: conventional load (i.e., base load), transportation electrification load, heating electrification load, and BTM PV (Equation 1).

Equation 1. Structure of ISO-NE's Net Hourly Load Forecast

$$\begin{aligned}&Net\ Hourly\ Load\\ &\qquad = Hourly\ Conventional\ Load + Hourly\ EV\ Load + Hourly\ Heat\ Pump\ Load\\ &\qquad - Hourly\ BTM\ PV\ Generation\end{aligned}$$

Load forecasts can be considered either net or gross. Net forecasts represent the load monitored by ISO-NE, inclusive of the load reductions from BTM PV systems. Gross forecasts represent the load that would have occurred in the absence of those BTM PV reductions. For ISO-NE, "BTM PV" refers to all solar PV resources that are not market participants.[11]

ISO-NE's load forecasting process begins with historical hourly load data, which serves as the foundation for the hourly forecast model. ISO-NE's annual energy forecast is simply the sum of its hourly peak

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[10] We use this naming convention as it more closely resembles the geography of the subareas. Synapse labels of SME, CME, and NME correspond to ISO-NE subareas of SME, ME, and BHE, respectively. ISO-NE zones are available at: https://www.iso-ne.com/about/key-stats/maps-and-diagrams#system-planning-subareas.

[11] ISO-NE. 2025. "Final 2025 Photovoltaic (PV) Forecast." March 24. Slide 27. Available at: iso-ne.com/static-assets/documents/100021/2_2025_final_pv_forecast.pdf.

forecast over the entire year.[12] Further, ISO-NE's region-wide forecast is simply the sum of each load-zone forecast.[13]

The first step in the forecasting process involves "grossing" or reconstituting historical metered load to remove the effects of BTM PV. To create historical hourly gross load, ISO-NE adds back the estimated amount of historical BTM PV to the historical load data. Thus, gross energy represents what consumption would have been without reductions from BTM PV.

ISO-NE does not remove any electrification load from the historical gross energy data when constructing the economic conventional load forecast.[14] This is due to both the lack of uniform heating electrification and transportation electrification data across the ISO-NE service territory and the minimal amount of electrification present in the historical gross load.

ISO-NE uses regression models to forecast conventional load using the historical gross load as the core variable. Forecast conventional hourly load is modeled based on regression and neural network models that incorporate three types of dependent variables: weather variables, calendar indicator variables[15] and statistically adjusted end-use (SAE) trend variables which are interacted with other variables.[16] These variables all inform the daily energy model, which then informs the hourly models.

The SAE trend variables are designed to capture the impact of EE that is not already contained in the baseload forecast.[17] The SAE trend variables are composed of three variables: *XHeat*, *XCool*, and *XOther*.

- *XHeat* contains information on heating technology saturation and efficiency along with demographic variables such as personal income and household size.[18] *XHeat* is held constant at its value in 2024 through the study period so that heating electrification from ISO-NE's heating

[12] ISO-NE. 2024. "Forecast Modeling." September 27. Slides 7 and 8. Available at: iso-ne.com/static-assets/documents/100015/lf2025_modeling.pdf.

[13] Ibid.

[14] Correspondence with ISO-NE regarding the CELT 2024 forecast, AskISO Case Number 00097066. Given that there is only BTMPV reconstitution in the CELT 2025 forecast, this is also true of the CELT 2025 forecast.

[15] The calendar indicator variables are used to indicate the effect of a particular month, day of week, holiday, or number of daylight hours per day.

[16] ISO-NE. 2024. "Base Load Modeling Update & Preliminary Results." December 13. Slide 8. Available at: iso-ne.com/static-assets/documents/100018/lf2025_mdl_updates_results_final.pdf.

[17] ISO-NE. 2025. "Updates to Forecast Data Sources." September 27. Slide 4. Available at: https://www.iso-ne.com/static-assets/documents/100015/lf2025_datasources.pdf.

[18] Itron. 2024. "Statistically Adjusted End-Use (SAE) Modeling." Slide 11. Available at: iso-ne.com/static-assets/documents/100015/intro-to-sae.pdf.

electrification forecast is not double counted within the baseline trend.[19] *XHeat* is interacted with heating related weather variables.[20]

- *XCool* contains information on cooling end-uses such as technology saturation and efficiency along with personal income.[21] *XCool* interacts with cooling-related weather variables.[22]
- *XOther* contains information on non-heating and cooling load such as appliances and lighting as well as personal income.[23] The *XOther* variable interacts with the calendar variables.[24]

ISO-NE forecasts heating electrification and transportation electrification separately. ISO-NE adds their hourly demand forecasts to the conventional hourly load forecasts to produce the gross hourly load forecast.

The net load forecast is equal to the gross load minus the separately forecasted BTM PV generation.

This integrated approach allows ISO-NE to account for both load increases from electrification and reductions from distributed generation, resulting in a balanced and accurate forecast.

ISO-NE develops coincident and non-coincident peak forecasts. Coincident peak forecasts represent each load zone's peak relative to ISO-NE's peak, while non-coincident peak forecasts represent the highest peak irrespective of when ISO-NE peaks. ISO-NE also develops deciles of each forecast. The two most commonly presented deciles are the 50/50 forecast, representing the peak demand level expected every two years and defined as having a 50 percent chance of being exceeded each year, and the 90/10 forecast, representing the peak demand level expected every ten years and defined as having a 10 percent chance of being exceeded each year.[25]

Figure 2 shows the four types of gross peak load forecasts, including the effects of electrification, for Maine in CELT 2025.

[19] ISO-NE. 2024. "Trend Variables in the Base Load Forecast." December 13. Slide 21. Available at: iso-ne.com/static-assets/documents/100018/lf2025_trendvars.pdf.

[20] Id. Slide 5.

[21] Itron. 2024. "Statistically Adjusted End-Use (SAE) Modeling." Slide 11. Available at: iso-ne.com/static-assets/documents/100015/intro-to-sae.pdf.

[22] ISO-NE. 2024. "Trend Variables in the Base Load Forecast." December 13. Slide 5. Available at: iso-ne.com/static-assets/documents/100018/lf2025_trendvars.pdf.

[23] Itron. 2024. "Statistically Adjusted End-Use (SAE) Modeling." Slide 11. Available at: iso-ne.com/static-assets/documents/100015/intro-to-sae.pdf.

[24] ISO-NE. 2024. "Trend Variables in the Base Load Forecast." December 13. Slide 5. Available at: iso-ne.com/static-assets/documents/100018/lf2025_trendvars.pdf.

[25] ISO-NE. n.d. Load Modeling Gguide for ISO New England Network Model. Page 1. Available at: iso-ne.com/static-assets/documents/rules_proceds/isone_plan/othr_docs/load_modeling_guide.pdf.

Figure 2. CELT 2025 50/50 and 90/10 coincident peak gross load forecasts for Maine, by season

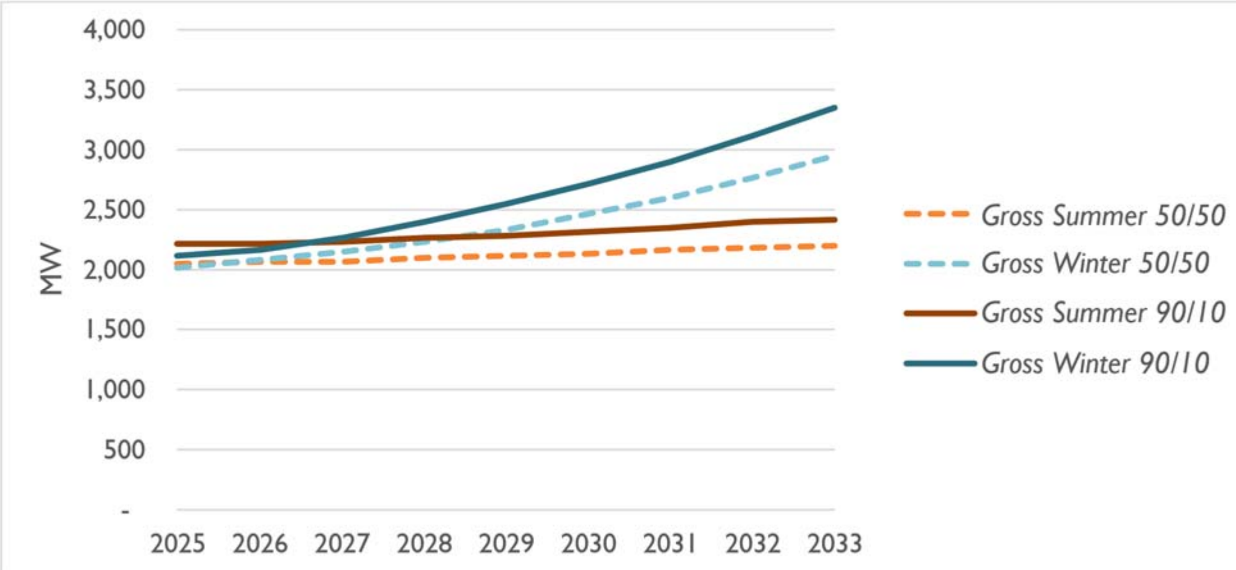
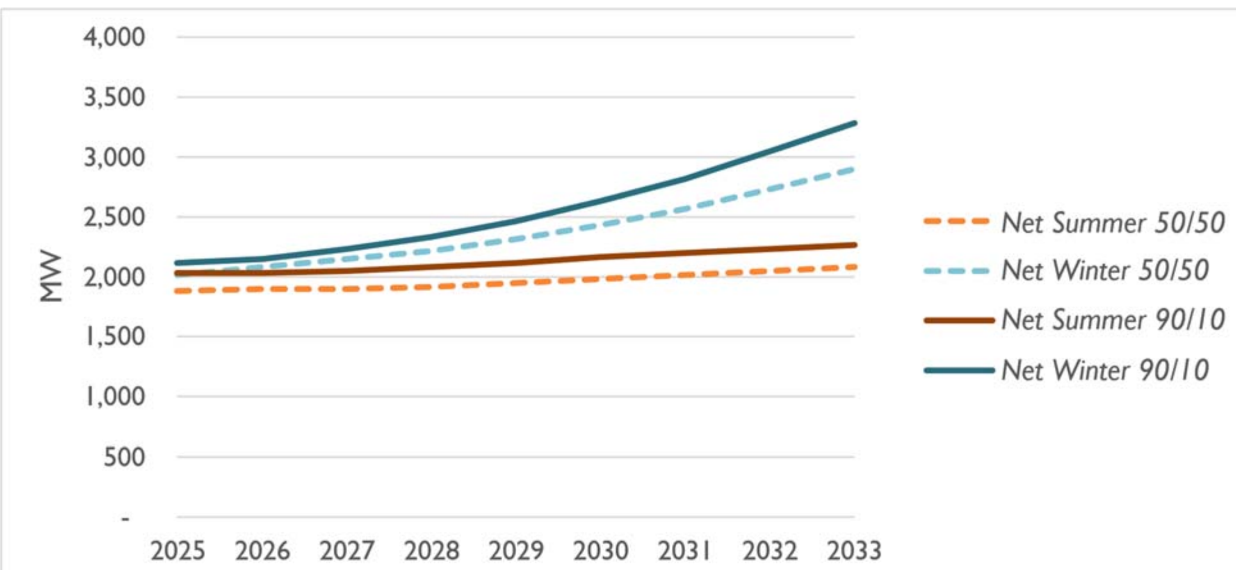


Figure 3 presents the four types of net peak load forecasts for Maine in CELT 2025, which removes BTM PV from the gross forecast. Notably, the 90/10 net peak forecast during the winter season is higher than the summer season net peak for the entire forecast period.

Figure 3. CELT 2025 50/50 and 90/10 coincident peak net load forecasts for Maine, by season



Comparison of ISO-NE forecasts with historical loads

Figure 4 shows the past 10 years of annual energy consumption in Maine, along with the projected gross energy and conventional energy through 2033 from the CELT 2025 forecast. The historical total gross energy declined at an average annual rate of 0.31 percent, while the forecast gross energy is projected to grow at an average annual growth rate of 1.97 percent. This substantially higher growth rate reflects growing peak loads primarily driven by building and transportation electrification. On the other hand, the forecast conventional energy grows at an average annual growth rate of 0.17 percent, representing a 0.48 percent annual growth rate difference compared to historical energy. However, both the historical energy and forecast conventional energy are generally flat.

Figure 4. Comparison of historical energy and CELT 2025 forecast gross and conventional energy for Maine

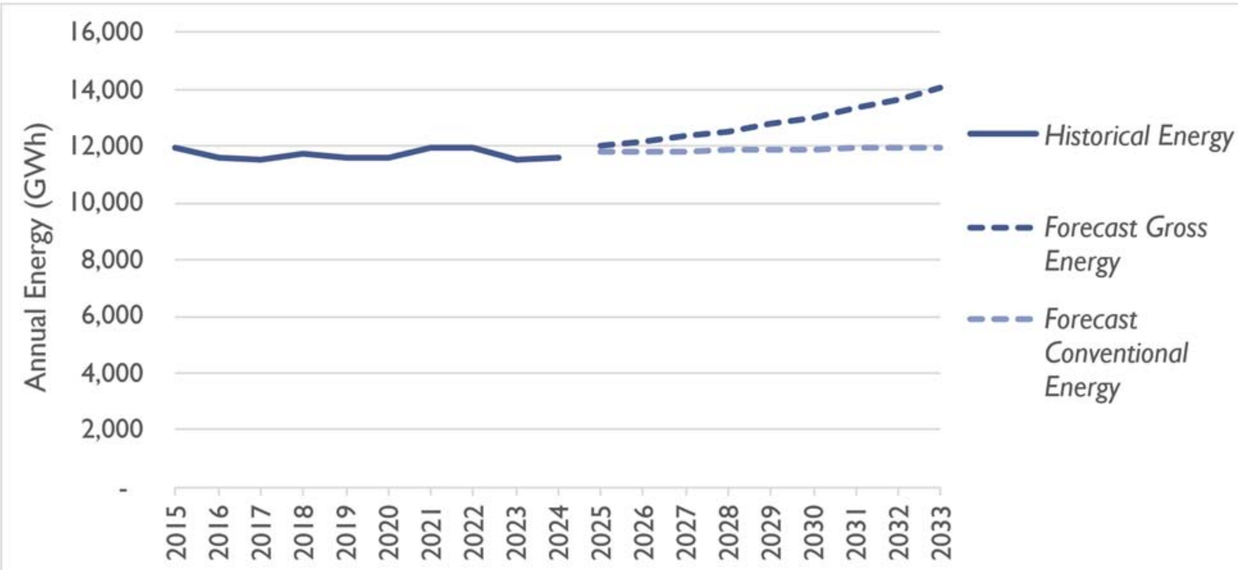


Figure 5 shows the past 10 years of historical gross peak loads and the forecast of gross and conventional peak loads through 2033 in Maine, split seasonally into summer and winter peaks. The figure indicates that conventional peak load forecasts generally follow historical trends. In contrast, the winter gross load peak forecasts are projected to grow substantially faster, driven by heating electrification.

Figure 5. Historical gross total peak loads, total gross peak load forecast, and base peak load forecast for Maine, CELT 2025

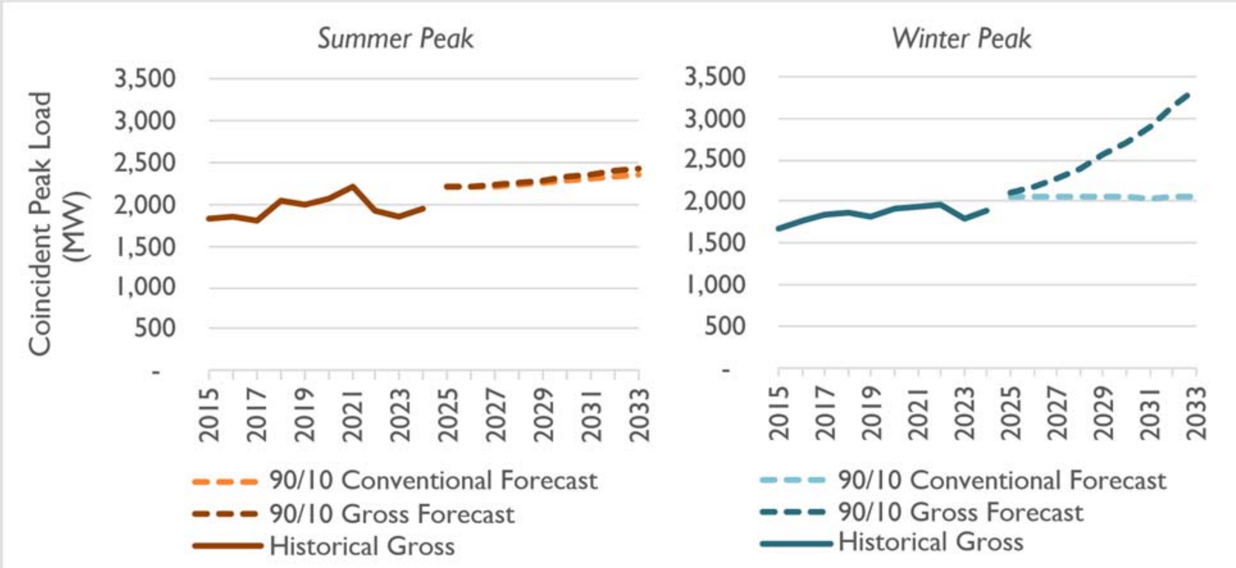


Table 1 summarizes annual growth rates by season for both historical peak loads and forecast peak loads. The growth rate of the summer conventional peak forecasts is comparable to the historical gross peak growth rate. In contrast, the winter growth rate of the conventional load peak is more than 1 percentage point lower than historical winter growth trends. The forecast growth rate for winter gross peak load shows the most notable difference compared to historical gross peaks, driven by heating electrification.

Table 1. Comparison of annual growth rates of seasonal peak loads

	Summer Peak Annual Growth Rate (%)	Winter Peak Annual Growth Rate (%)
Historical Gross Peak (2015 to 2024)	0.82%	1.33%
Forecast 90/10 Conventional Load Peak (through 2033)	0.78%	0.03%
Forecast 90/10 Gross Load Peak (through 2033)	1.14%	5.96%

Subarea peak demand forecasts

ISO-NE provided subarea-level forecasts in CELT 2025. We compiled the 90/10 net coincident peak forecasts for summer and winter by subarea in Figure 6. As shown in this figure, winter net coincident peak loads already exceed summer peaks in the NME and CME subareas across the forecast horizon. In the SME subarea, summer peaks are initially higher, but ISO-NE projects winter peak demand to overtake summer peak demand around 2029. Across all three subareas, winter peak loads grow more rapidly than summer peaks and increase substantially through 2033, indicating that winter demand is expected to be the primary driver of future peak load growth in Maine.

Figure 6. Net coincident peak demand by season and subarea in Maine, CELT 2025

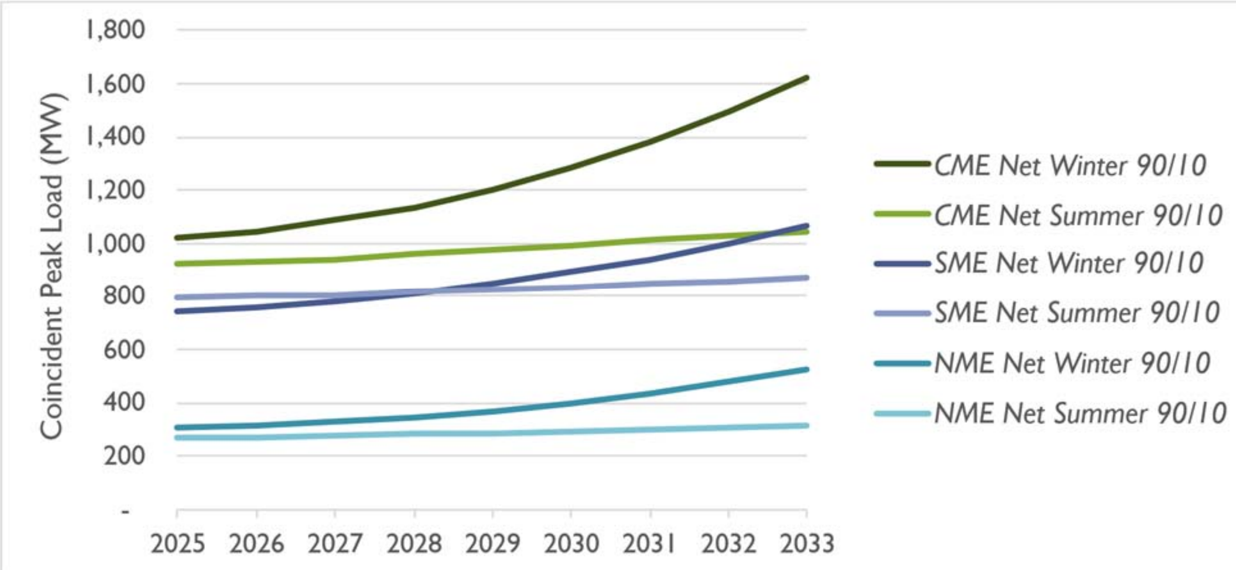


Figure 7 and Figure 8 provide the 90/10 forecast by season for the state of Maine broken out by load component. Conventional load continues to account for the majority of the total load, although almost all growth is from non-conventional loads. Our peak load analyses will use the conventional load estimates for the summer and winter seasons as mentioned in the previous section. CELT 2025 projects electrification of heating to grow substantially over time, growing to over half the size of the conventional load by 2033. With the switch to a winter peaking system, the effects of BTM PV are lessened, but remain non-zero.

Figure 7. CELT 2025 summer 90/10 coincident peak demand by component, for Maine

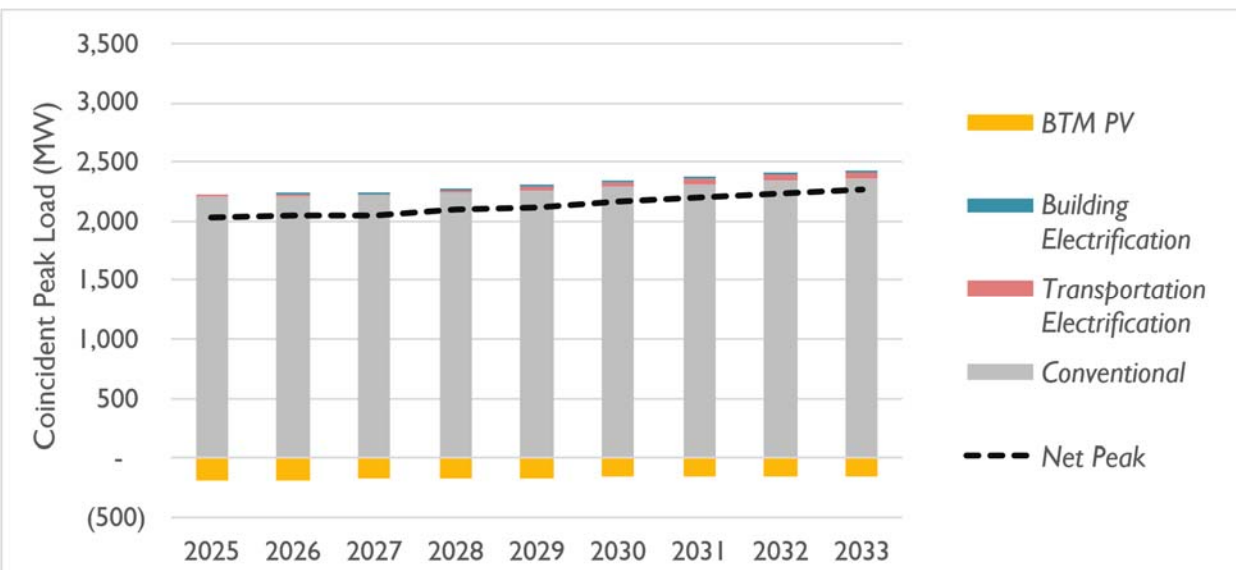
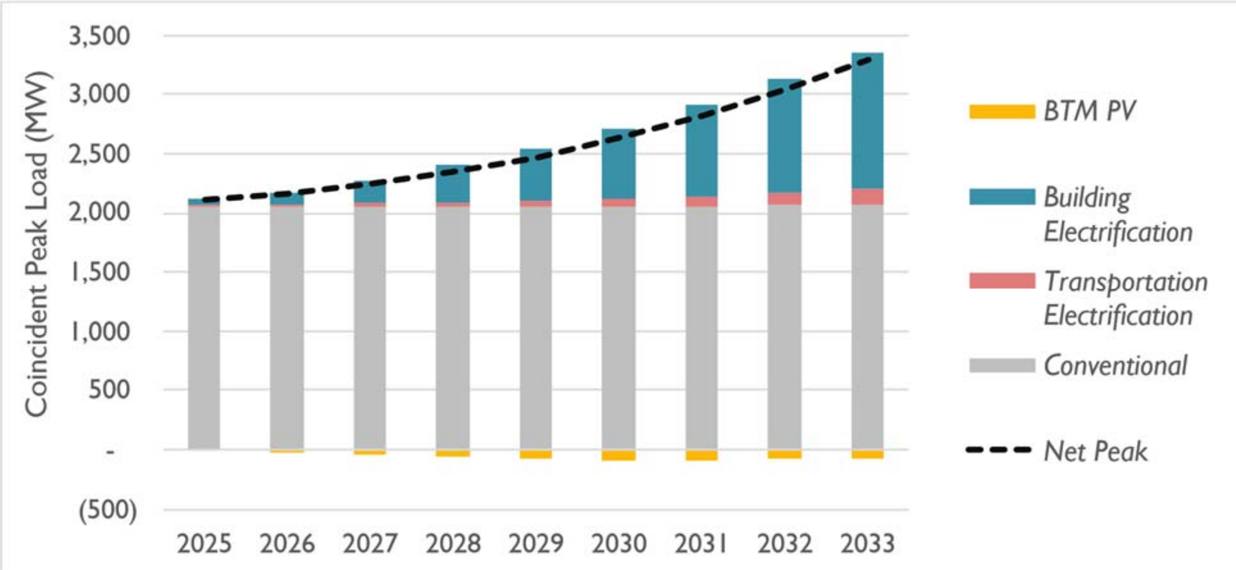


Figure 8. CELT 2025 winter 90/10 coincident peak demand by component, for Maine



Development of Peak-Day Hourly Conventional Load Profiles

Methodology for developing peak day load shapes

Analyzing summer and winter peak loads requires examining hourly peak load contributions from each key load component: conventional loads, electrification loads, and load reductions from distributed energy resources (DERs) such as solar PV. This analysis is critical because the timing of peak hours and hourly load shapes are expected to shift significantly as heat pumps and EVs add substantial loads to the electric grid over the coming decade. To address this, our methodology develops peak-day hourly loads for each load component and combines their impacts to identify coincident peak hours for each subarea.

To develop hourly loads on the peak days, we first construct hourly load shapes that reflect both (a) the current mix of end use appliance and equipment and (b) the weather conditions corresponding to ISO-NE's 90/10 loads. Our methodology for developing hourly loads for non-conventional loads will be discussed in Section 3. For conventional loads, we apply our own methodology to create hourly load shapes for peak days during the summer and winter seasons.

We rely on recent hourly load and weather data rather than the load shapes used in ISO-NE's 2024 CELT or 2025 CELT. The primary reason we adopted our own methodology is that, at the time we developed it, the only available CELT load shape data were from the 2024 CELT, which relied on outdated load shapes derived from historical loads in 2002. The load shapes from 2002 are unlikely to be representative of current load patterns due to significant changes in end-use technologies in buildings since that time, including the widespread transition from fluorescent and incandescent lighting to energy-efficient LEDs, as well as increased air conditioning saturation. While the 2025 CELT appears to incorporate updated load shape methodologies based on more recent data, it had not yet been released at the time we developed our methodology.

We used a four-step approach to develop our own hourly load shapes. First, we obtained the temperature assumptions that ISO-NE used to develop its 90/10 subarea peak loads for the 2024 CELT. ISO-NE relied on Portland weather data for the entire state as the only temperature data we received from ISO-NE were for Portland.[26] Table 2 below provides these assumptions, along with the temperatures corresponding to the 50/50 load conditions. Because our analysis focuses on subarea peak loads, we derived temperature values for the other subareas by applying the typical temperature differences between Bangor (representing NME), Augusta (representing CME), and Portland (representing SME), using ASHRAE climate design conditions.[27] Table 3 presents the resulting temperature values for each subarea corresponding to ISO-NE's 90/10 load conditions.

Table 2. CELT 2024 weather points, dry-bulb (deg F)

	Winter	Summer
50/50 peak load	6.4	87.4
90/10 peak load	1.8	91.8

Table 3. Assumed temperatures for ISO-NE's 90/10 peak load by region

City (Region)	Winter	Summer
Portland (SME)	1.8	91.8
Augusta (CME)	-1.5	92.0
Bangor (NME)	-4.8	92.7

Second, we reviewed recent historical weather data to identify historical peak load days for both summer and winter that experienced severe weather conditions comparable to the temperatures shown in Table 3. We selected June 7, 2021, as the representative summer peak day and February 21, 2020, as the representative winter peak day.

Third, we obtained historical substation-level hourly load data at the substation level from ISO-NE's historical load data sets[28] and estimated total hourly loads for the selected historical peak days.

Finally, we adjusted the total hourly loads to account for the impacts of BTM PV on the load shapes for two reasons: (a) the historical load data used to derive the load shapes already reflects some level of existing BTM PV and (b) the 2025 CELT conventional load forecast excludes solar load impacts from the

[26] The data obtained via personal communication with ISO-NE staff on December 3, 2024. Note we did not obtain weather data ISO-NE used for CELT 2025.

[27] ASHRAE Climatic Design Conditions 2009/2013/2017/2021/2025. Available at: https://ashrae-meteo.info/v2.0/; ASHRAE climate data are used by HVAC contractors to determine space heating and cooling loads.

[28] ISO-NE. "Nodal Load Weights." Last accessed September 27, 2024. Available at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/nodal-load-weights.

conventional load and, instead, provides those impacts separately.[29] More specifically, we derived hourly BTM PV load estimates based on both ISO-NE's historical estimates of annual energy from BTM PV in Maine[30] and hourly BTM PV production data.[31] We adjusted our hourly conventional load curve to remove the load reductions from existing BTM PV.

Hourly loads on peak days

Once we constructed the 90/10 hourly load shape for each seasonal peak and load area from the historical years, as described above, we could extrapolate these findings out to 2025 and future years. To do this, we converted the hourly load shapes into percentages of the peak hourly load. We then applied these percentages to the seasonal zonal peak loads forecasted in the 2025 ISO New England CELT Report, creating an hourly load shape of the peak day for each season and load area from 2025 through 2033. Below, we present our 90/10 hourly load estimates for the winter and summer peak days for 2025.

Figure 9 presents our estimates of 90/10 summer peak day hourly conventional loads for each subarea for 2025. The summer peak hour occurs in the afternoon and early evening between 2 pm and 7 pm for each subregion. Each subregion sees a rise in load as customers return home; however, this impact is less pronounced in the NME subarea.

[29] ISO-NE's recent solar PV data shows 40 to 70 MW of BTM PV load impacts during the summer, which is equivalent of 2 to 3 percent of the peak load for the entire state.

[30] ISO-NE. 2025. "2025 Forecast Data." *Load Forecast Materials.* May 1. Available at: https://www.iso-ne.com/system-planning/system-forecasting/load-forecast.

[31] ISO-NE. 2025. "Behind-the-Meter PV Data." *Load Forecast Materials.* November 11. Available at: https://www.iso-ne.com/system-planning/system-forecasting/load-forecast.

Figure 9. 2025 summer peak day hourly load for the conventional loads

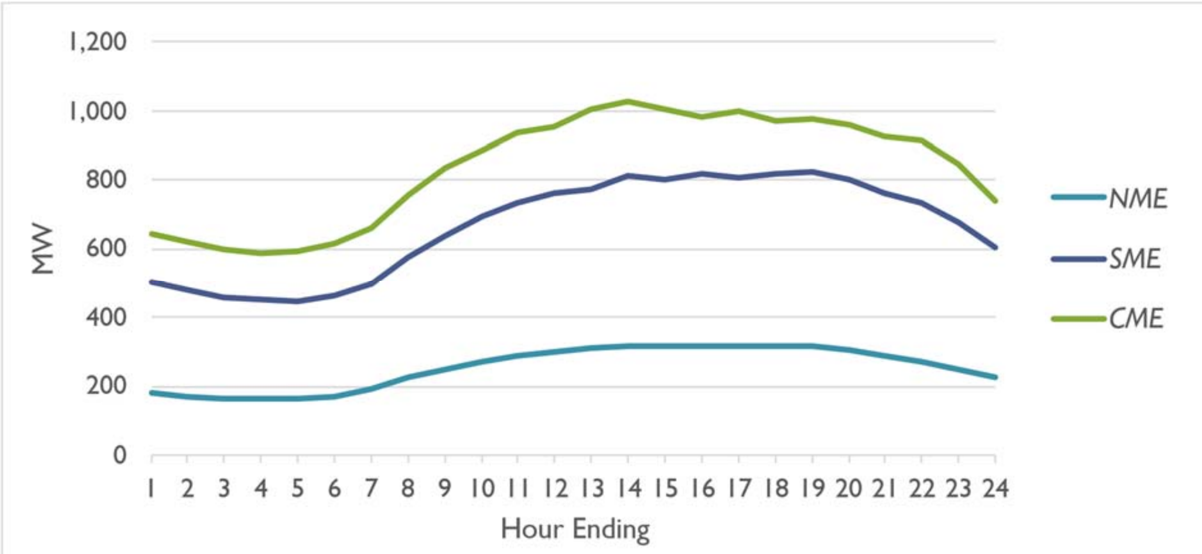
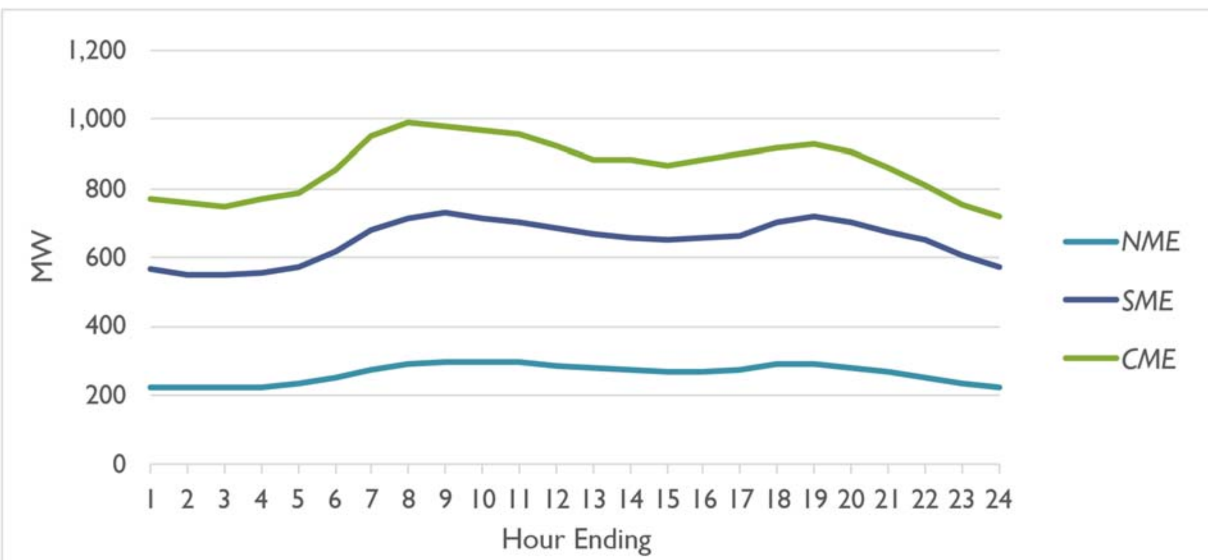


Figure 10 presents our estimates of 90/10 winter peak day hourly loads for each subarea for 2025. The winter peak hour occurs either in the morning around 8 am to 10 am or in the evening between 6 pm and 7 pm, with a dip in demand before and after those times. This pattern is once again less pronounced in NME and most pronounced in CME. Additionally, the midday dip is the most pronounced in the CME.

Figure 10. 2025 winter peak day hourly load for the conventional loads



3. RESOURCE-SPECIFIC LOAD FORECASTS

3.1. Heating Electrification

This section summarizes our approach to developing our peak load forecasts for space and water heating electrification from 2024 to 2033.

Overall load forecasting approach

Analyzing the impact of space and water heating electrification on peak loads requires examining both heat pump adoption as a result of fuel switching, as well as hourly heating consumption. We started by projecting heat pump adoption in Maine, from which we disaggregate the state's three load subareas based on current heating equipment penetration: NME, CME, and SME. We then modeled hourly heat pump load impacts in each subarea and applied heat pump load curves to the subarea-specific heat pump adoption forecasts to develop total hourly demand and peak forecasts.

Our peak load forecasting approach for heating electrification has three scenarios: low-, medium-, and high-adoption. The Low scenario is aligned with the 2024 ISO-NE CELT forecast for heating electrification.[32] The Medium and High scenarios are based on Efficiency Maine Trust's (EMT) projections of heat pump adoption, reflecting state targets.[33]

Heat pump stock forecast

Our heat pump adoption forecasts build on the underlying assumptions of the state-wide heat pump adoption forecasts from the 2024 CELT's heating electrification forecast for Maine, which serves as an input for all three scenarios.[34] The CELT forecasts the number of heat pump conversions as a percent of the residential households or square feet of commercial buildings currently heating with natural gas, fuel oil, and propane. The CELT study disaggregates heat pump adoption by type (e.g., GSHP) and whether systems are "full" heat pumps that serve the entire building heating load or "partial" systems that rely on existing fossil-fuel heating systems during the coldest hours.

We started with a projection of the state-wide adoption by percent of households with each legacy fuel. To convert this to an estimated number of heat pumps by zone, we used National Renewable Energy Laboratory (NREL)

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[32] ISO-NE. 2024. "Final 2024 Heating Electrification Forecast." April 27. Available at: https://www.iso-ne.com/static-assets/documents/100010/final-2024-heating-electrification-forecast.pdf.

[33] State of Maine Office of Governor Janet T Mills. July 21, 2023. Available at: https://www.maine.gov/governor/mills/news/after-maine-surpasses-100000-heat-pump-goal-two-years-ahead-schedule-governor-mills-sets-new.

[34] ISO-NE. 2024. "Final 2024 Heating Electrification Forecast." April 27. Available at: https://www.iso-ne.com/static-assets/documents/100010/final-2024-heating-electrification-forecast.pdf.

’s ComStock and ResStock data to calculate the current number of residential households or commercial square feet in each zone that use natural gas, propane, and fuel oil for space and water heating.[35,36] We then multiplied the adoption percentage numbers by the existing legacy heating fuel stock to get the total number of heat pump conversions by year.

Scenarios

To develop the high-, medium-, and low-load scenarios, we built from the ISO CELT heat pump adoption forecast. For the Medium and High scenarios, we used data from EMT Triennial Plan VI[37] that incorporates the state heat pump targets. The state has set a goal of at least 115,000 households heating with whole-home heat pumps and an additional 130,000 partial heat pump systems by 2030.

- For the **High** scenario, we assume that the state meets the whole home heat pump target and continues growth thereafter.
- For the **Medium** scenario, we assume slower progress toward the state’s heat pump target and slower growth after 2030.
- For the **Low** scenario, we use the ISO-NE forecasts of heat pump adoption by fuel type and system type, based on the 2024 CELT forecast.[38,39]

For heat pump water heaters, we modeled the Medium scenario to correspond to ISO-NE’s forecasts of heat pump water heater adoption and system type in the 2024 CELT forecast. We then assumed the High and Low scenarios achieve 25 percent higher and lower adoption than the Medium scenario, respectively.

Figure 11 below shows the statewide residential heat pump adoption by scenario. In the High scenario, over 275,000 residential households have adopted heat pumps by 2033, reaching 48 percent of households in the state. In the Medium and Low scenarios, there are roughly 230,000 and 215,000 additional residential households with heat pumps in 2033, reaching a penetration rate of 39 and 36 percent, respectively. In the High scenario, 62 percent, or over 177,000 households, have adopted full systems, as shown in Figure 12. In the Medium and Low scenarios, 54 percent and 43 percent of heat pump adoption is of full systems, respectively.

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[35] National Renewable Energy Laboratory. 2024. ComStock Public Datasets: Metadata. End Use Load Profiles for the U.S. Building Stock. Available at: https://comstock.nrel.gov/.

[36] National Renewable Energy Laboratory. 2024.2 Release. ResStock Public Datasets: Metadata. End Use Load Profiles for the U.S. Building Stock. Available at: https://resstock.nrel.gov/datasets.

[37] EMT. 2024. *Triennial Plan VI Appendix D: Long-Term Target Results*. Available at: https://www.efficiencymaine.com/docs/TPVI_Appendix_D_Long_Term_Target_Results_11-24.pdf.

[38] ISO-NE. 2024. “Final 2024 Heating Electrification Forecast.” *Appendix IV: State Space Heating Adoption.* April 27. Available at: https://www.iso-ne.com/static-assets/documents/100010/final-2024-heating-electrification-forecast.pdf.

[39] Note that the 2024 and 2025 ISO-NE CELT forecast do not appear to differ in their adoption forecasts for Maine.

Figure 11. Statewide residential heat pump adoption by scenario: total households (left) and penetration rate (right)

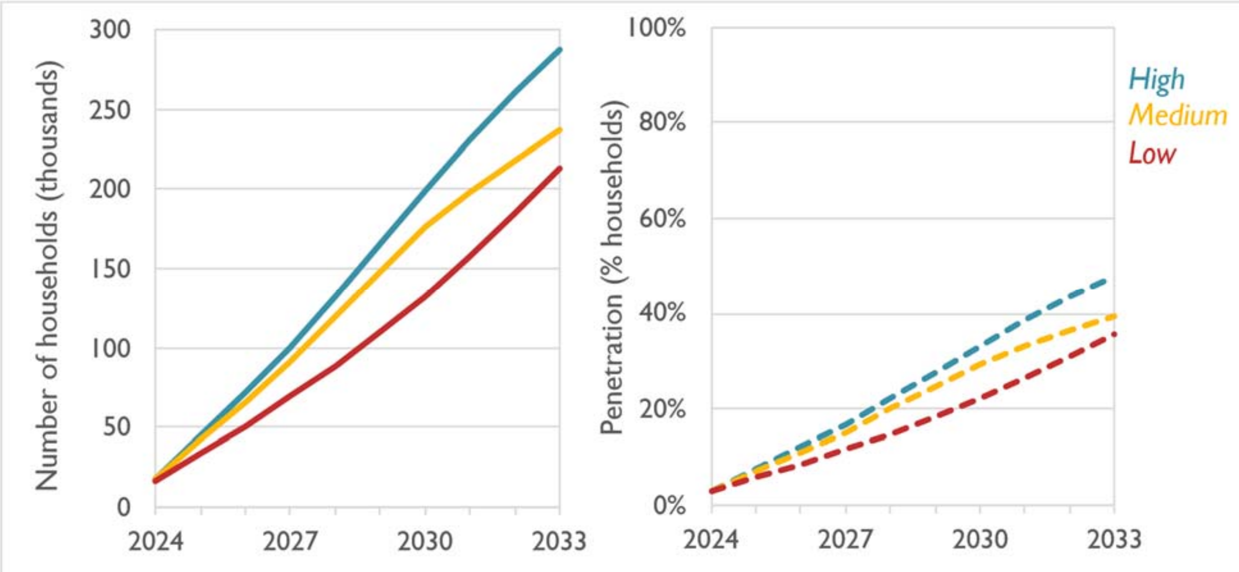


Figure 12. Statewide residential full heat pump adoption by scenario: total households (left) and penetration rate (right)

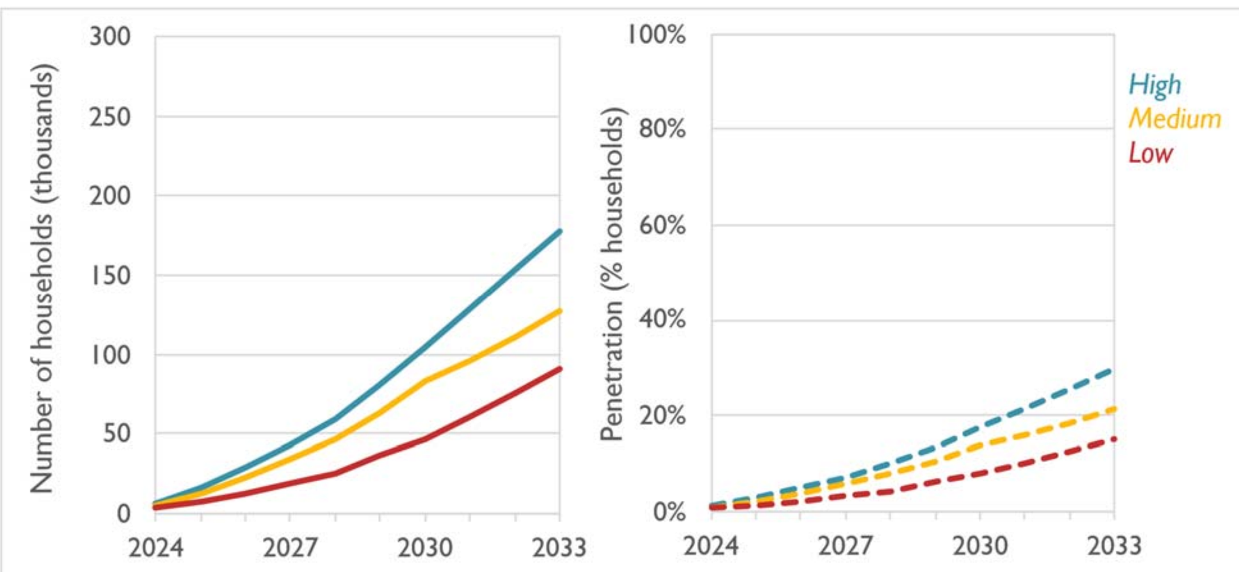


Figure 13 shows the commercial heat pump adoption trajectories by scenario. By 2033, roughly 127 million square feet of commercial buildings have adopted heat pumps in the High scenario, corresponding to a penetration rate of 38 percent. In the Medium scenario, 107 million square feet of commercial buildings have adopted heat pumps. 87 million square feet have adopted heat pumps in the Low scenario. We assumed the same number of partial systems in each scenario and varied the number of full systems by scenario. In the Low scenario, 70 percent of commercial heat pump adoption, representing over 60 million square feet, is projected to be full systems, and 30 percent, or 26 million square feet, is heated by partial systems by 2033. The Medium and High scenarios project full heat pump systems to account for 76 percent and 80 percent of heat pump adoption by 2033, respectively.

Figure 13. Statewide commercial heat pump adoption by scenario: total square feet (left) and penetration rate (right)

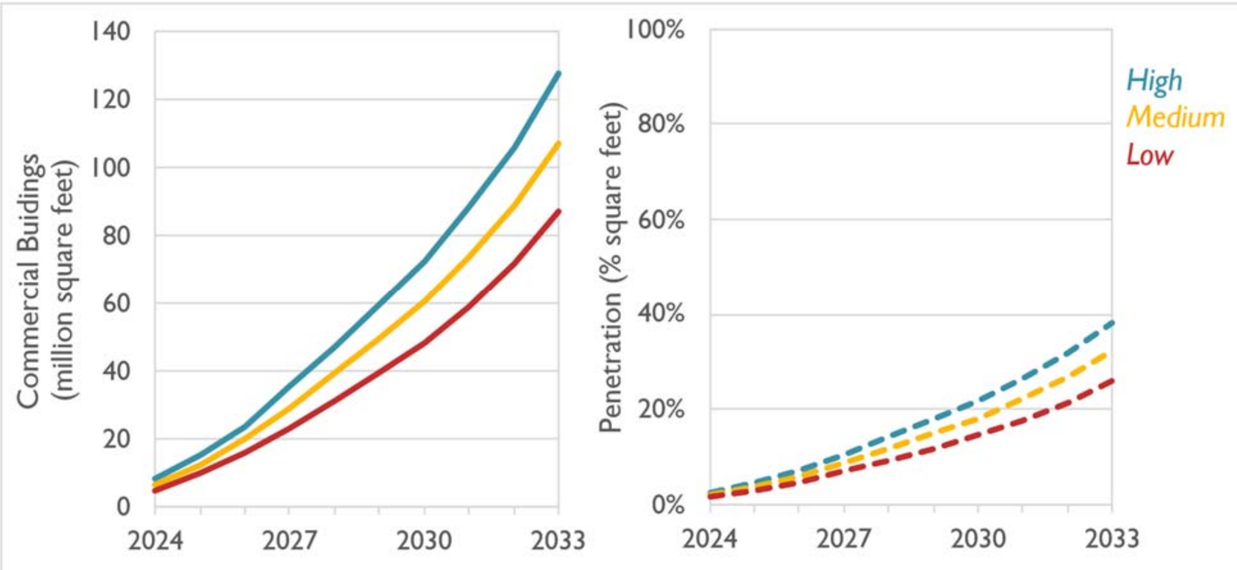
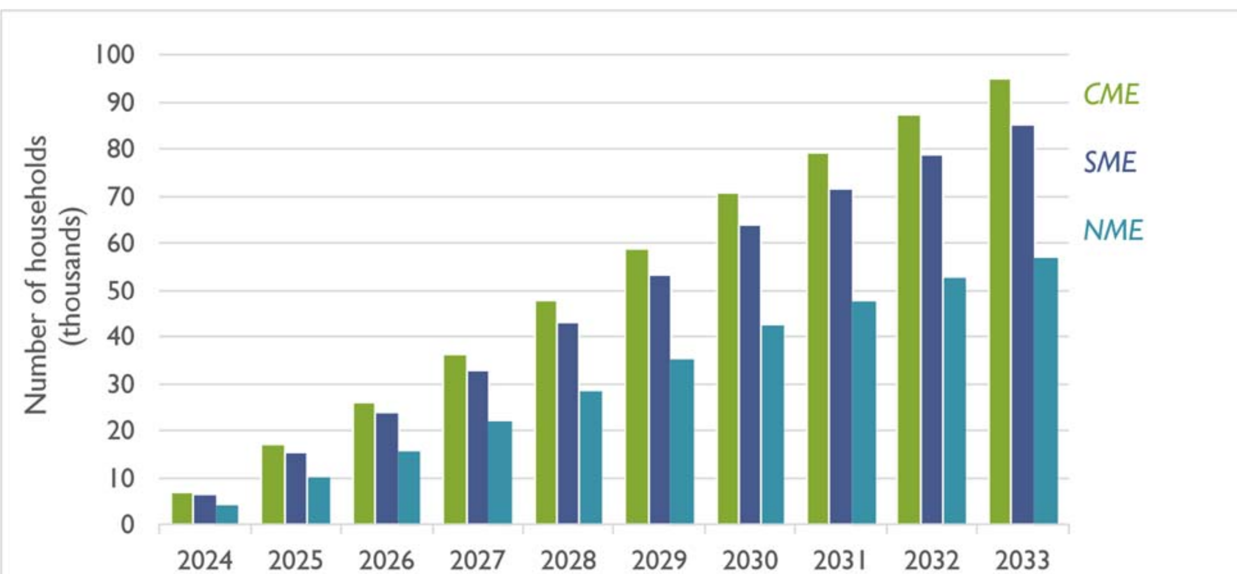


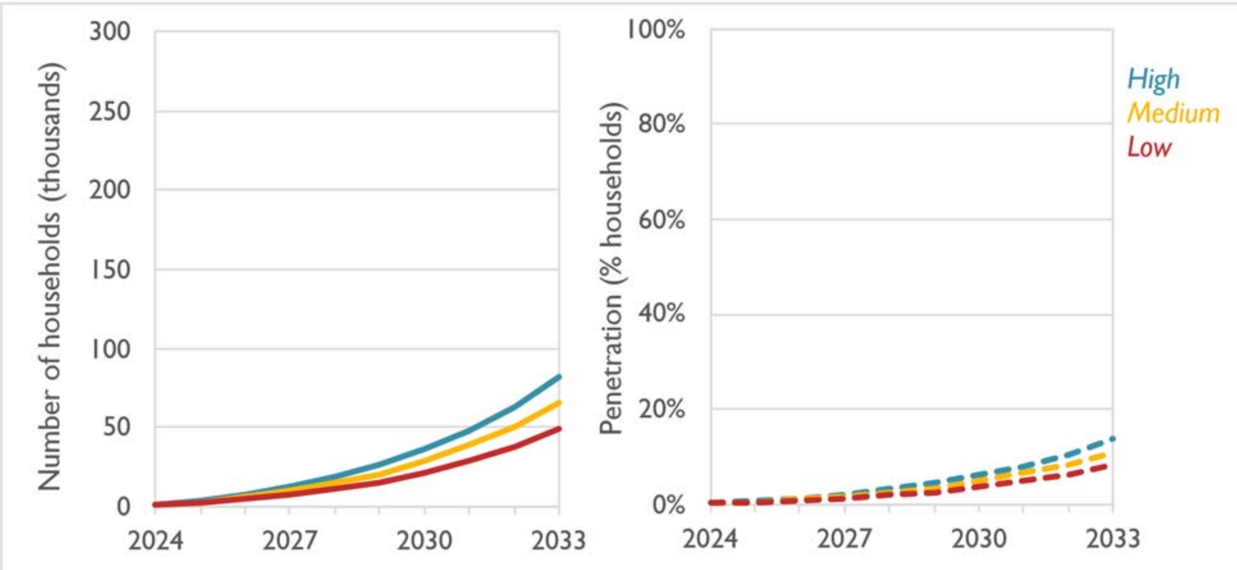
Figure 14 shows the breakout of residential heat pump adoption in the Medium scenario by region. We allocated the statewide heat pump adoption trajectory to the regions based on the total number of households heating with natural gas, propane, and fuel oil in each region. The CME subarea has the highest population of the three regions and thus leads in total adoption. The SME subarea has the highest share of existing households heating with gas, and thus over 60 percent of the statewide conversions of gas to electric heat pumps occur in the SME region.

Figure 14. Residential heat pump adoption by region, Medium scenario



Finally, Figure 15 shows the adoption and penetration rate of heat pump water heaters (HPWH) by scenario. By 2033, over 81,000, or 14 percent of households have adopted HPWHs in the High scenario.

Figure 15. Statewide residential heat pump water heater adoption by scenario: total households (left) and penetration rate (right)



Peak load impact forecast

To develop the peak load forecast from the annual heat pump adoption forecast, we modeled hourly heat pump energy demand curves. We translated the stock forecast values into estimates of hourly electricity demand based on heating load, coefficient of performance (COP), and weather assumptions.

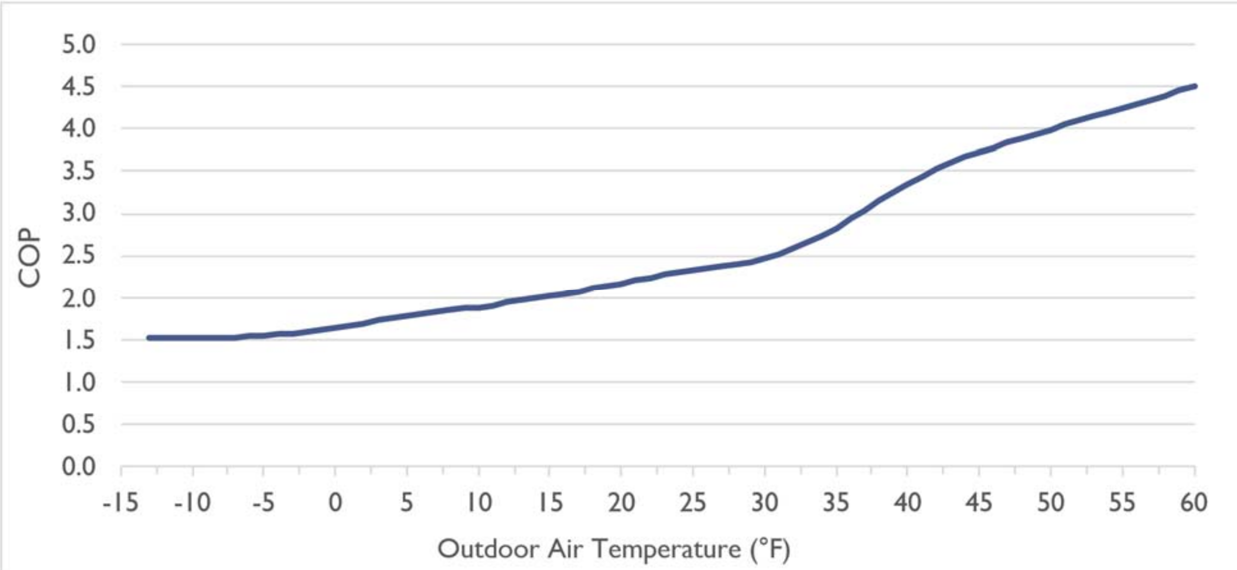
Key assumptions and methods

Heat pump COP

The COP measures the efficiency of a heat pump. COP is defined as the ratio of useful heating or cooling output to the total energy input. Because heat pumps transfer heat rather than generating it, heat pump COPs can be greater than 1, meaning that more heating or cooling is provided than the energy input. The temperature of the outdoor air or other heat reservoirs (e.g., ground, pond) that heat pumps rely on influences the efficiency of heat pumps (in particular, air-source heat pumps, which extract heat from ambient air.) Air-source heat pumps perform most efficiently when outdoor temperatures are high and are less efficient when outdoor temperatures are very low. In contrast, ground-source heat pump operation is not affected by the conditions of outdoor air. However, since most heat pumps installed today for space heating are air-source heat pumps which extract heat from the outdoors, our analysis assumes the performance of air-source heat pumps.

To relate COP to temperature, we applied a linear regression model. EMT recently filed an evaluation study of heat pump performance, along with its Triennial Plan VI filing. This evaluation study analyzed the performance of numerous residential heat pumps and developed an average COP curve by temperature, as shown in Figure 16 below.[40] We applied this COP curve for both residential and commercial heat pumps in our analysis, as most commercial heat pumps in Maine are expected to rely on mini-split heat pumps—the dominant system type in the residential sector in the state.[41]

Figure 16. Average measured COP vs. outdoor air temperature



Source: Figure 6, Efficiency Maine Residential Heat Pump Impact Evaluation. Prepared by Ridgeline Analytics and Guidehouse for Efficiency Maine Trust. March 2024. Available at: *https://www.efficiencymaine.com/docs/Efficiency_Maine_Residential_Heat_Pump_Impact_Evaluation_Report-2024.pdf.*

For residential HPWH, we assume a COP of 3.88, based on a typical Rheem unit.[42,43] We use this COP for both residential and commercial HPWHs. Consistent with ISO-NE CELT forecast, we assume 10 percent of commercial heat pump water heater adoption relies on an electric resistance booster (with a COP of 1) to serve 15 percent of hot water load.[44] We calculated a weighted average COP of 3.84 for commercial HPWHs, accounting for these boosters.

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40 Ridgeline Analytics and Guidehouse. 2024. *Efficiency Maine Residential Heat Pump Impact Evaluation*. Prepared for Efficiency Maine Trust. Available at: https://www.efficiencymaine.com/docs/Efficiency_Maine_Residential_Heat_Pump_Impact_Evaluation_Report-2024.pdf.

41 Based on conversations with EMT, most heat pumps for commercial buildings are minisplit heat pumps.

42 *Based on the Uniform Energy Factor for Rheem's Performance Platinum heat pump water heater (Model XE50T10H45U0). Available at:* https://files.rheem.com/blobazrheem/wp-content/uploads/sites/2/THD-PPEH5-30-REV-5-GEN-7-Hybrid30-amp_0702.pdf.

43 This COP is consistent with the 2024 CELT results for HPWH load.

44 ISO-NE. 2024. "Final 2024 Heating Electrification Forecast." April 27. Slide 68. Available at: https://www.iso-ne.com/static-assets/documents/100010/final-2024-heating-electrification-forecast.pdf.

Load assumptions

We estimated residential heating energy consumption per household and commercial heating energy consumption per thousand square feet using heating energy consumption data from NREL's ResStock and ComStock data for Maine.[45] Table 4 shows the estimated space and water heating consumption by region for residential buildings. Table 5 shows the estimated space and water heating consumption per thousand square feet for commercial buildings.

Table 4. Total space heating and water heating required per household by region (MMBtu)

End use	Northeastern Maine (NME)	Southeastern Maine (SME)	Central Maine (CME)
Space heating	82	68.3	73.3
Water heating	9	9.8	8.9

Table 5. Total space heating and water heating required per thousand square feet (MMBtu)

End use	Commercial buildings
Space heating	27.01
Water heating	9.98

To estimate electricity consumption for heat pumps, we first developed hourly heating energy consumption estimates and heating energy requirements based on hourly end-use load profiles, hourly weather data from NREL's ResStock and ComStock databases, and the average efficiency of fossil fuel heating equipment. We then applied a regression of energy demand and hourly temperatures to determine the required space heating, space cooling, and water heating load (MMBtu) per heating degree day. We then determined the kWh impacts on electric system load by adjusting for the COP of the heat pump. For space heating, we used the relationship between heat pump COP and temperature (Figure 16) to calculate the kWh-per-heat pump for each hour of our weather year data.[46]

Consistent with the ISO-NE's assumptions in the 2024 CELT forecast, we assume that partial heat pump systems switch to fossil or wood backup heating when temperatures are below 20 degrees Fahrenheit.[47] Also, consistent with the results from EMT evaluations of heat pump usage in Maine, we assume that some full whole-home systems supplement their heat pumps with other heating sources below -5

[45] See https://resstock.nrel.gov/ and https://comstock.nrel.gov/.

[46] We did not assume any variation in HPWH COP over time or by temperature.

[47] ISO-NE. 2024. "Final 2024 Heating Electrification Forecast." April 27. Slide 74. Available at: https://www.iso-ne.com/static-assets/documents/100010/final-2024-heating-electrification-forecast.pdf.

degrees Fahrenheit.[48] We modeled three use cases: 1) the heat pump is supplemented by fossil fuel heating, 2) the heat pump is increasingly supplemented by electric resistance systems as the temperature decreases, and 3) the heat pump continues to operate down to the coldest temperature, with some reductions in COP to reflect the decreased efficiency of the heat pump at those temperatures.

We did not analyze any electric load impacts from cooling and air conditioning from heat pump installations. This is because the net impacts on electric peak load from adoption of heat pumps to serve heating load will likely be small, as new heat pumps are highly efficient and may even save energy if they replace existing, less efficient air conditioning units. ISO-NE's forecast of summer peak demand from heating electrification is very small, roughly 1 percent of the winter peak demand impacts.[49]

Total coincident peak load impact

As described in Section 2, we determined the coincident peak day for the summer and winter for each subarea. To estimate the 90/10 peak load from heat pumps, we identified the temperature used in ISO-NE's 2024 CELT forecast for 90/10 load conditions for the state (1.8 degrees Fahrenheit in Portland, Maine).[50] We then assessed historical weather data to find a representative date of real weather data for Portland Maine whose lowest temperature matches the temperatures for ISO-NE's 90/10 load conditions (February 21, 2020). We used weather data for that date for all three subareas. Figure 17 shows the hourly outdoor temperature for each region. Note the lowest temperatures identified by ISO-NE for "90/10 load" conditions are not as severe as the "90/10 temperatures", which represent the coldest temperatures expected to occur once every 10 years. Appendix A provides a sensitivity analysis of heat pump peak loads under the 90/10 temperatures. As winter loads become more heating-dominated in the future, 90/10 loads are more likely to occur at 90/10 temperatures.

[48] Ridgeline Analytics and Guidehouse. 2024. *Efficiency Maine Residential Heat Pump Impact Evaluation*. Figure 24. Prepared for Efficiency Maine Trust. Available at: https://www.efficiencymaine.com/docs/Efficiency_Maine_Residential_Heat_Pump_Impact_Evaluation_Report-2024.pdf.

[49] ISO-NE. 2024. "Final 2024 Heating Electrification Forecast." April 27. Available at: https://www.iso-ne.com/static-assets/documents/100010/final-2024-heating-electrification-forecast.pdf.

[50] Email communications with ISO-NE staff on December 3, 2024.

Figure 17. Hourly outdoor temperature on 90/10 load condition by region

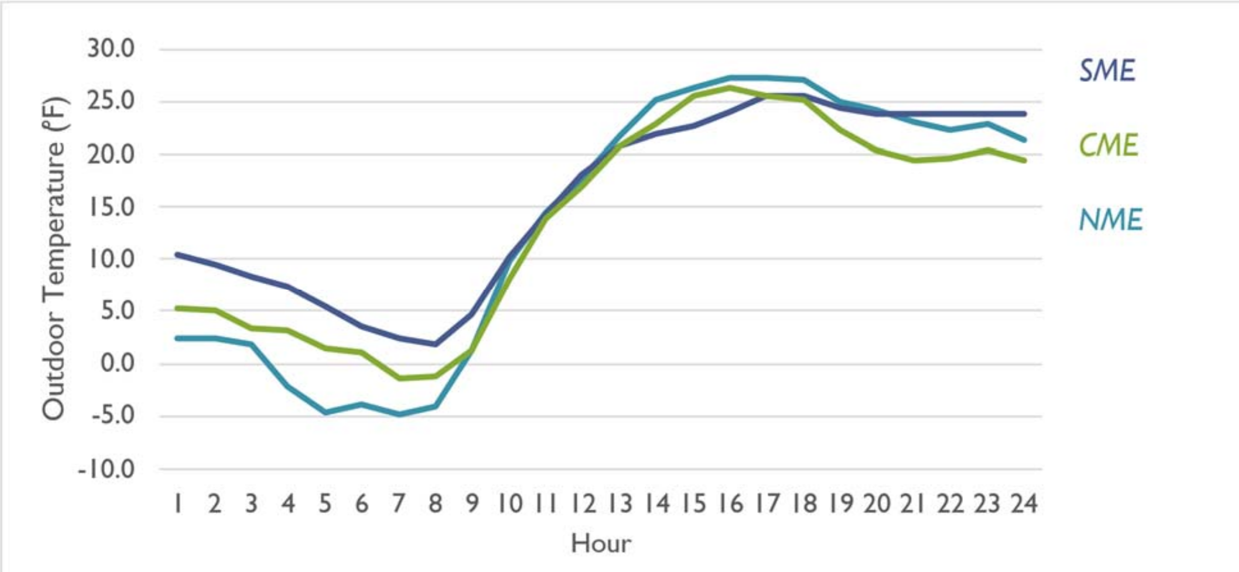
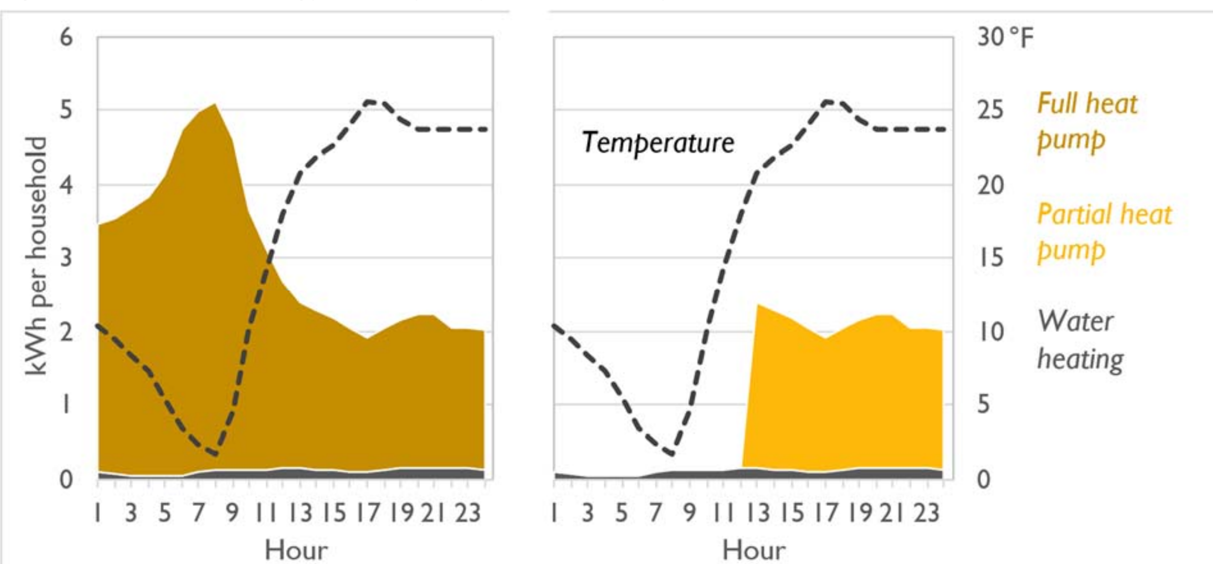


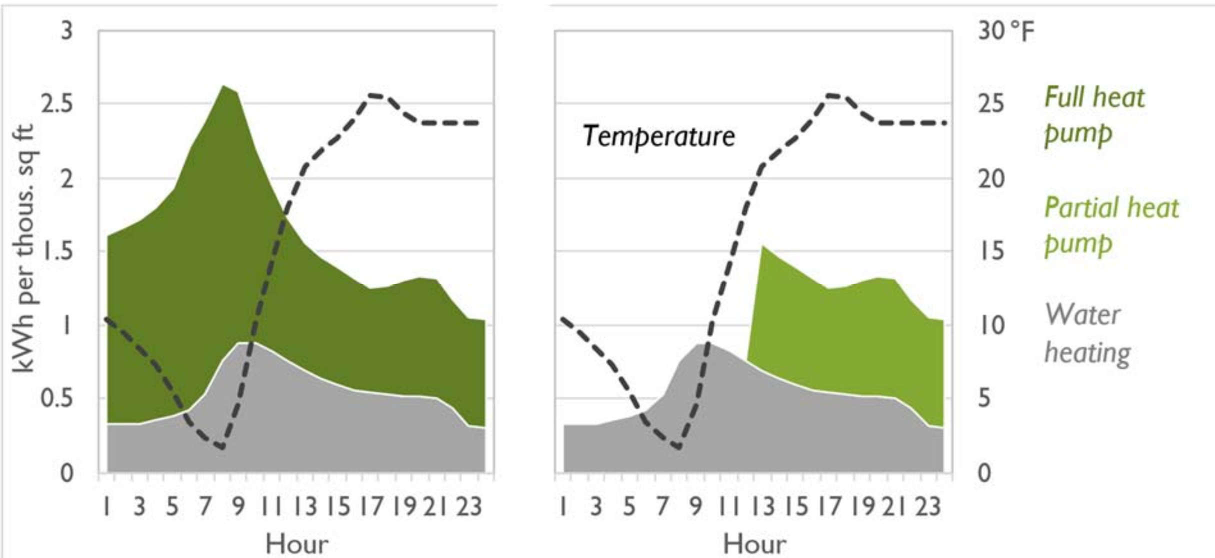
Figure 18 and Figure 19 show the hourly demand by end use for a) a residential household and b) a thousand square foot commercial property, respectively, on February 21 in the SME subarea. As shown in Figure 18, residential water heating is a relatively small share of per household consumption compared to space heating. For a household with a full heat pump system, per-household residential energy consumption peaks at just above 5 kW at the coldest temperature (1.8 degrees Fahrenheit) (Figure 18, left). Conversely, a partial heat pump system does not turn on below 20 degrees Fahrenheit; the coldest hours are instead met by the supplemental fossil fuel heating system (Figure 18, right). Thus, the per-household peak electric consumption is less than half the consumption of the full system.

Figure 18. Residential energy consumption per household by end use, SME



Similarly for commercial buildings, the full heat pump system's electricity consumption peaks at nearly 2 kWh per thousand square feet at the coldest temperature (Figure 19). In comparison, for the partial system, the peak hours are met by the backup heating system, so the total consumption during the peak day is less than half of the full system. Note that Figure 19 shows the kWh impacts per thousand square feet for a commercial building with newly electric domestic hot water (grey). While these HPWH impacts appear large compared to those for a space heating system, the penetration of commercial buildings adopting space heating heat pumps is roughly six times greater than that of commercial buildings adopting HPWHs. Thus, average HPWH consumption represents a much smaller share of total commercial building heating electrification impacts (see Figure 20.)

Figure 19. Commercial energy consumption per thousand square feet by end use, SME



We applied these hourly load profiles for all the projected heat pumps by system type to calculate the total demand by segment and end use. We sum the total demand for each heat pump segment (i.e., residential, commercial, space heating, and water heating) at these winter peak hours to determine the contributions heating electrification will have on peak demand. Figure 20 shows the statewide heating electrification load under the Medium scenario by sector and end use. The largest contributor to peak heating electrification load in the winter is from residential space heating, followed by commercial space heating. In comparison, water heating has a relatively small impact, representing only 2.5 percent of the total hourly peak load expected from building space and water heating end uses.

Figure 20. Statewide heating electrification hourly energy consumption on 90/10 load conditions in the Medium scenario, by end use and sector

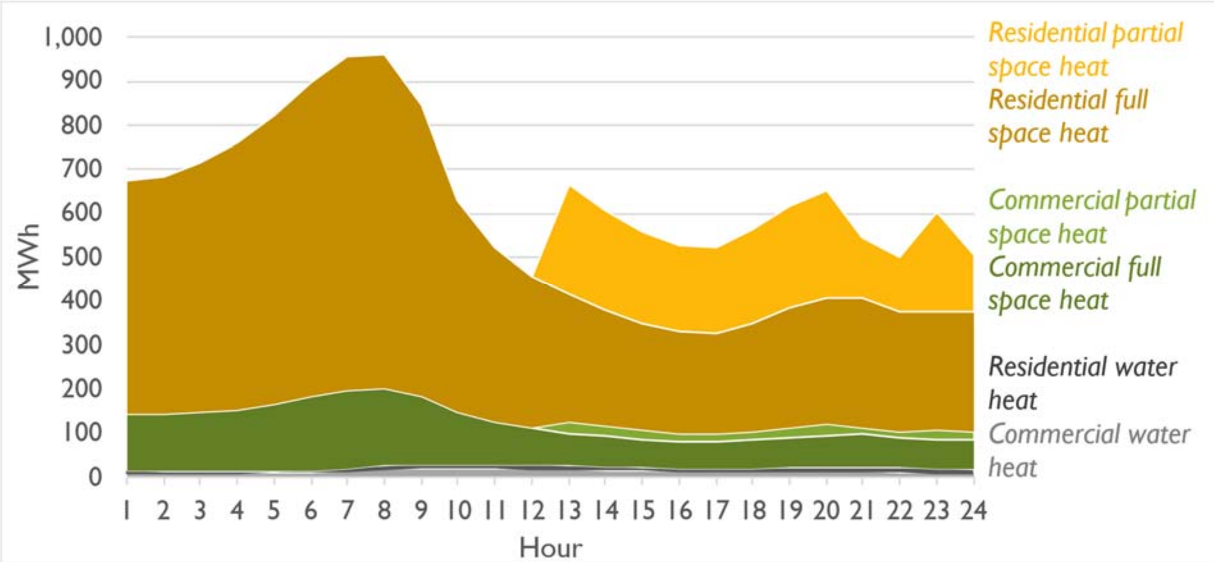


Figure 21 shows the statewide winter peak load from heat pumps by scenario over time. By 2033, heating electrification contributes to an additional 964 MW of peak load in 2033 in the Medium scenario. Compared to the Medium scenario, the High and Low scenarios are 37 percent higher and 28 percent lower in 2033, respectively.

Figure 21. Statewide heating electrification 90/10 peak loads by scenario

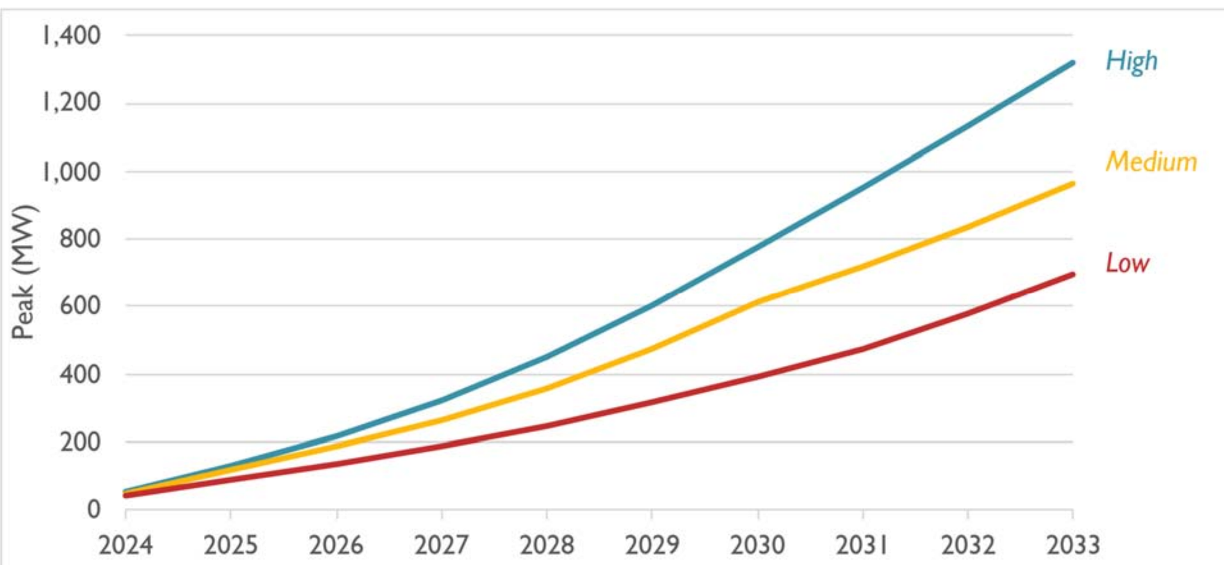
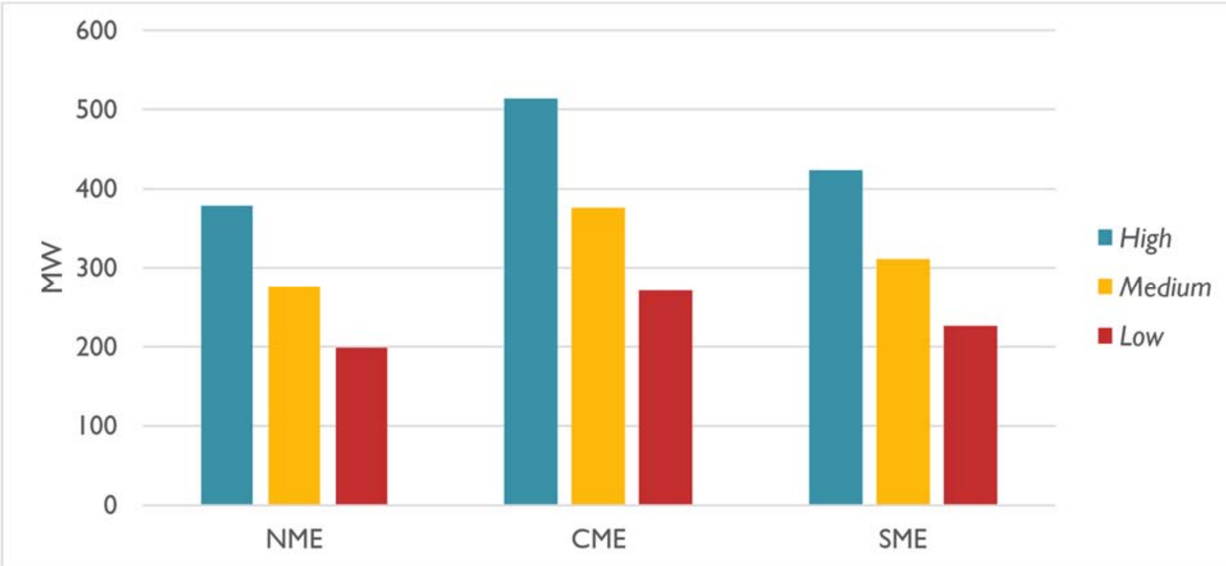


Figure 22 shows the winter 2033 peak load by region and scenario. Across all scenarios, the CME region is responsible for the largest share of peak load (39 percent), compared to 29 percent in NME and 32 percent in SME.

Figure 22. Heating electrification 90/10 peak loads by region and scenario in 2033



Comparison with ISO-NE's CELT forecast

Figure 23 below compares our winter 2033 energy forecast to ISO-NE's 2024 and 2025 CELT forecasts. Figure 24 shows the statewide winter peak heat pump load under each scenario alongside the statewide winter heat pump load from ISO-NE's 2024 and 2025 CELT forecasts.

Overall, our forecasts are comparable to ISO-NE's forecasts. However, ISO-NE projects a substantially lower peak load in NME compared to other regions—more so than in our forecast. For instance, ISO-NE estimates heat pump load in NME to be about half of that in the SME subarea, whereas our forecast for NME is only about 11 percent lower than SME.[51] Conversely, our Low scenario estimates for CME and SME are 34 percent and 22 percent lower than CELT 2024 forecasts, respectively. Overall, our estimate for the Low scenario, which uses the same heat pump stock forecast as CELT 2024, projects a peak load that is 15 percent lower than CELT's estimate. This suggests that CELT 2024 assumes a higher unit-level kW peak impact than our analysis for the other regions.

The discrepancy in NME primarily stems from the ISO's methodology to estimate heat pump loads at the subarea level. Instead of forecasting heat pump adoption at the subarea-level, for the 2024 CELT ISO-NE forecasted heat pump adoption and energy and demand impacts at the statewide level and then allocated the impacts to each subarea based on the current share of electricity consumption by zone.[52] As a result, the 2024 CELT does not reflect future shifts in electricity usage across zones. Consequently, it likely underestimates heat pump-related peak loads in NME and overestimates them in other regions. We forecast a significantly higher peak demand in NME than ISO-NE's estimates (more than double in

[51] NME roughly corresponds with the ISO's Bangor Hydro (BHE) regional subarea.

[52] Based on personal communications with ISO-NE staff.

the Medium and High scenarios), reflecting greater electricity use driven by colder temperatures and heating electrification in northern Maine.

In CELT 2025, ISO-NE forecasts a 40 percent higher winter peak load impact from heat pumps than in the 2024 CELT forecast. The main difference behind this increase is that ISO-NE updated the weather data used: the overall heat pump adoption forecasts did not change between CELT 2024 and CELT 2025 for Maine.[53] In the CELT 2024 forecast, ISO-NE used data for only eight weather stations across New England, with only one in Maine (near Portland, as discussed above).[54] In 2025, ISO-NE now models 23 weather stations, including two locations in Maine: Portland and Bangor.[55] This provides more accurate weather and temperature assumptions for northern Maine, resulting in higher peak load estimates than CELT 2024. This again suggests that CELT 2025 has even higher unit-level kW peak impact than our analysis. The potential contributing factors to this difference include: (a) the heat pump COP curve our analysis used based on EMT's latest heat pump performance evaluation presents higher COP values under severely cold temperatures than what ISO-NE assumes in the 2025 CELT and (b) our heating energy output analysis based on ResStock and ComStock differs from ISO-NE's analysis in the 2025 CELT, even though ISO-NE also used ResStock and ComStock.[56]

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[53] ISO-NE. 2025. "Draft 2025 Heat Pump Forecast." February 21. Slide 7. Available at: https://www.iso-ne.com/static-assets/documents/100020/heat_fx2025_draft.pdf.

[54] ISO-NE. 2025. "Updates to Forecast Data Sources." September 27. Available at: https://www.iso-ne.com/static-assets/documents/100015/lf2025_datasources.pdf.

[55] ISO-NE. 2025. "Final 2025 Heat Pump Forecast." May 1. Slide 6. Available at: https://www.iso-ne.com/static-assets/documents/100023/heat_fx_2025.pdf.

[56] ISO-NE. 2025. "Final 2025 Heat Pump Forecast." May 1. Slide 65. Available at: https://www.iso-ne.com/static-assets/documents/100023/heat_fx_2025.pdf.

Figure 23. Heating electrification 90/10 peak loads by scenario and region in 2033, compared to ISO-NE 2024 and 2025 CELT

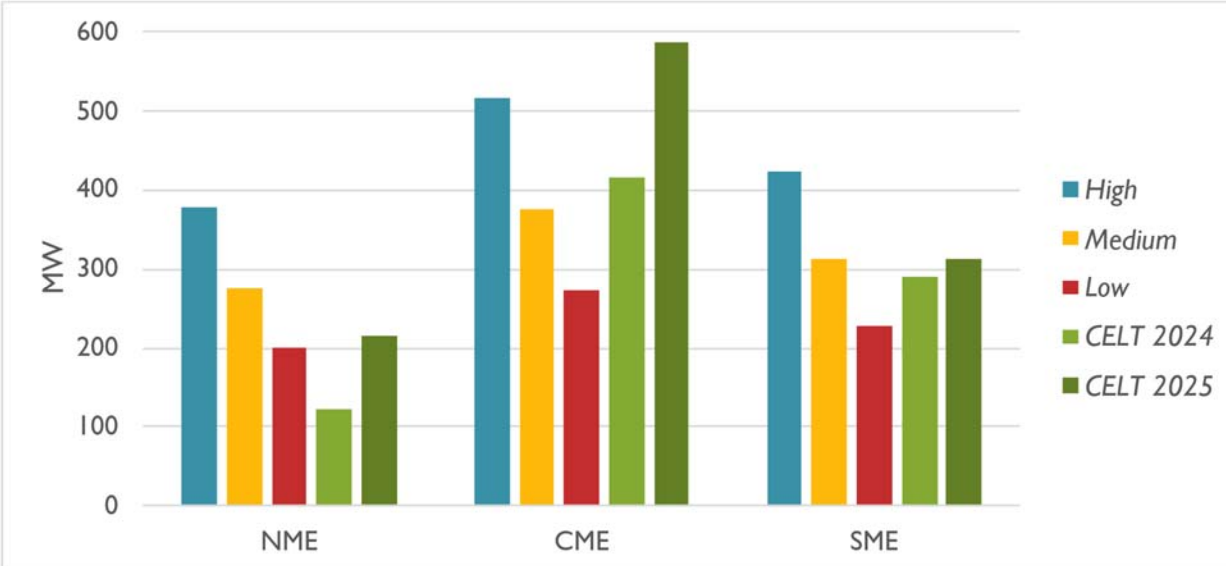
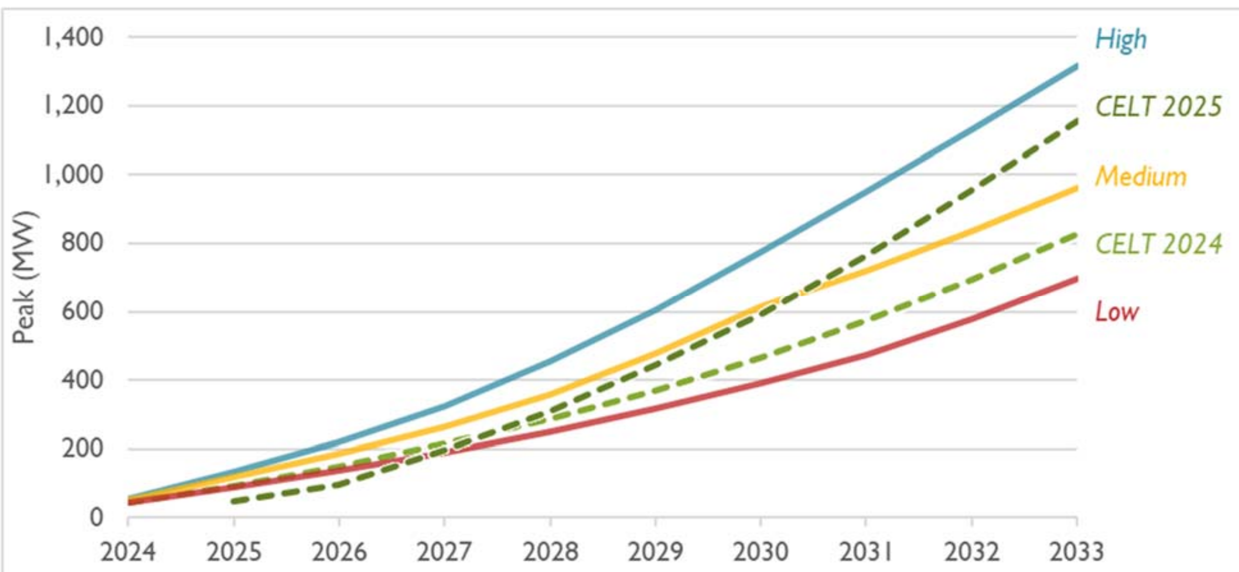


Figure 24. Statewide heating electrification 90/10 peak loads by scenario, compared to ISO-NE 2024 CELT and 2025 CELT



3.2. Transportation Electrification

This section summarizes our approach to developing our peak load forecasts for EV charging from 2024 to 2033 and presents the results.

Overall load forecasting approach

Analyzing EV charging impacts on summer and winter loads requires examining both EV adoption forecasts and hourly charging behavior. Due to differences in data availability, our analytical approach differs between light-duty vehicles (LDV) and medium- and heavy-duty vehicles (MDV/HDV). Both LDV and MD/HDV forecasts begin with a projection of EV stock in Maine, from which we allocate among the state's three load subareas based on current vehicle registration counts: SME, CME, and NME. We then apply load curves and charging pattern assumptions to the zone-specific EV stock forecasts to develop hourly seasonal demand and seasonal peak forecasts.

We analyze peak load impacts from EVs for three scenarios: Low, Medium, and High. The Low scenario assumes low EV adoption and widespread managed charging adoption, resulting in the lower bound of the potential load impact. The High scenario assumes high EV adoption and limited managed charging adoption, resulting in the upper bound. The Medium scenario represents a midpoint between the upper and lower bounds. Table 6 below provides a summary of our modeled scenarios.

Table 6. EV peak load forecast scenario description

	Low Scenario	Medium Scenario	High Scenario
EV Adoption	Low	Moderate	High
Managed Charging Adoption	High	Moderate	Low

EV Stock Forecast

Light-duty vehicles

Our subarea-level EV adoption model for LDVs builds on the state-wide EV sales scenarios forecasted in Dunsky's *Electric Vehicle Market Assessment,*[57] conducted for Efficiency Maine Trust. In this study, Dunsky analyzes the impacts of rebates and socio-economic factors on EV adoption in Maine and forecasts EV adoption for the Low, Medium, and High scenarios out to 2030. The study desegregates electric LDV adoption by plug-in hybrid electric vehicles (PHEV) and battery electric vehicles (BEV). According to the study, variables such as charging stations per mile of road and population density have a larger impact on the average number of EVs on the road than other factors such as EV rebates.[58] However, Dunsky selected EV rebate levels as the only driving factor in their modeling. Unlike the other variables under consideration, rebate levels are controlled by the State of Maine, and any change in rebate level will be available to all residents regardless of their location. The three scenarios Dunsky forecasts respectively are (1) no rebates, (2) low- and moderate-income (LMI) only rebates, and (3) status-quo rebates (at time of publication, July 2024).

[57] Dunsky Energy and Climate Advisors. 2024. *Electric Vehicle Market Assessment: Historical and Forecasted Adoption and Influence of Rebates*. Report prepared for Efficiency Maine Trust. Available at: https://www.efficiencymaine.com/docs/TPVI_Appendix_L3_EV_Market_Assessment.pdf.

[58] Ibid.

Table 7 provides a detailed description of Dunsky's scenario inputs and assumptions. As of November 2024, Efficiency Maine suspended all rebates except for LMI rebates.[59] To reflect this recent policy shift in the state, our analysis assumes the LMI only rebate scenario as the Medium scenario for EV adoption and uses the status quo and no rebates as the High and Low scenarios, respectively. We extend Dunsky's EV adoption forecast beyond 2030 to 2033 using linear interpolation. In addition, our analysis carries forward the assumption, drawn from Dunsky's EV adoption scenarios, that federal EV tax credits available at the time of the study would continue, although these credits expired at the end of 2025 following recent federal policy changes.[60] This assumption is consistent with ISO-NE's 2025 CELT, which was published prior to the federal policy change that led to the expiration of federal EV tax credits and therefore does not reflect that change.

Table 7. Dunsky EV adoption modelled scenarios

	Scenario 1: No Rebates	**Scenario 2: LMI Rebates Only**	**Scenario 3: Status Quo Rebate**
Efficiency Maine Rebates	None	<u>Non-LMI residential</u> BEVs: $0 PHEVs: $0 <u>Moderate income, Low income, and Commercial</u> BEVs: $2,000 PHEVs: $1,000 *In place through 2029*	<u>Non-LMI residential</u> BEVs: $2,000 PHEVs: $1,000 <u>Moderate income</u> BEVs: $3,500 PHEVs: $2,000 <u>Low income</u> BEVs: $7,500 PHEVs: $3,000 <u>Commercial</u> Average of $5,700 *In place thorough 2029*
Federal Tax Credit	BEVs: $7,500 PHEVs: $5,500 *In place through 2032*	BEVs: $7,500 PHEVs: $5,500 *In place through 2032*	BEVs: $7,500 PHEVs: $5,500 *In place through 2032*

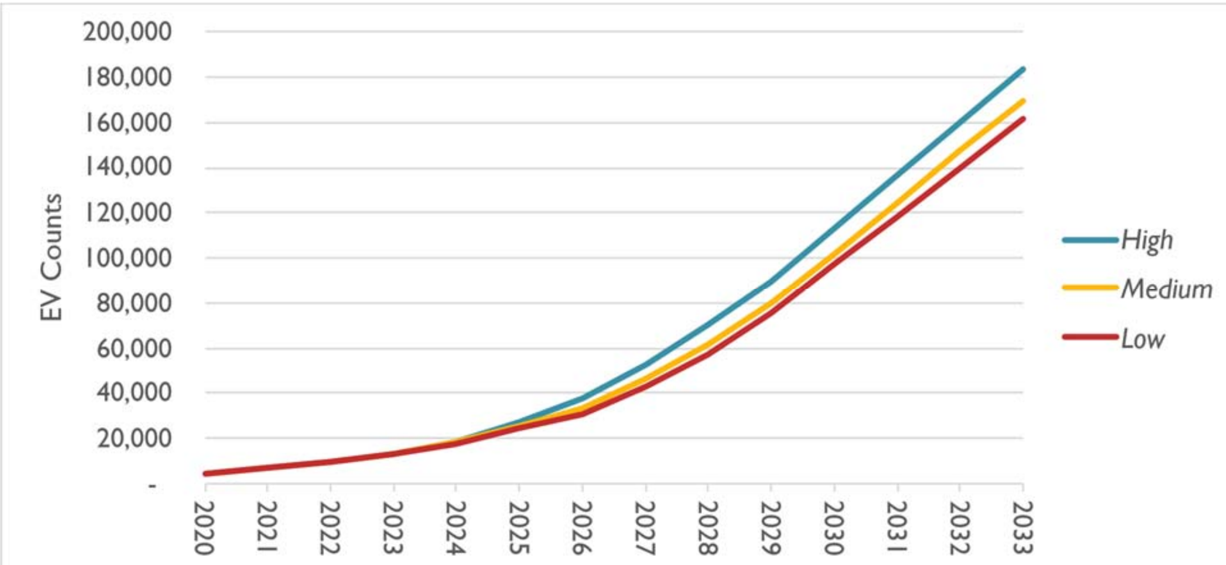
Source: Dunsky Energy and Climate Advisors. 2024. Electric Vehicle Market Assessment: Historical and Forecasted Adoption and Influence of Rebates. Report prepared for Efficiency Maine Trust. Available at: https://www.efficiencymaine.com/docs/TPVI_Appendix_L3_EV_Market_Assessment.pdf.

[59] Efficiency Maine. "Electric Vehicles." Last accessed November 16, 2024. Available at: https://www.efficiencymaine.com/electric-vehicle-rebates/.

[60] As a result, EV adoption and associated peak load impacts in our analysis may be overstated relative to a scenario in which federal EV tax credits are no longer available, consistent with the approach used in ISO New England's load forecasts.

Figure 25 below shows the total statewide number of electric LDVs in each of the three modeling scenarios through 2033. Following Dunsky, we project that electric LDVs will increase substantially over time, reaching approximately 161,000 to 183,000 vehicles by 2033, representing roughly 15 percent of today's registered LDVs in the state. The Medium and Low scenarios depict slightly lower adoption rates than the High scenario but still significant increases. The projections remain close in early years but diverge after 2026, with the High scenario accelerating more rapidly.

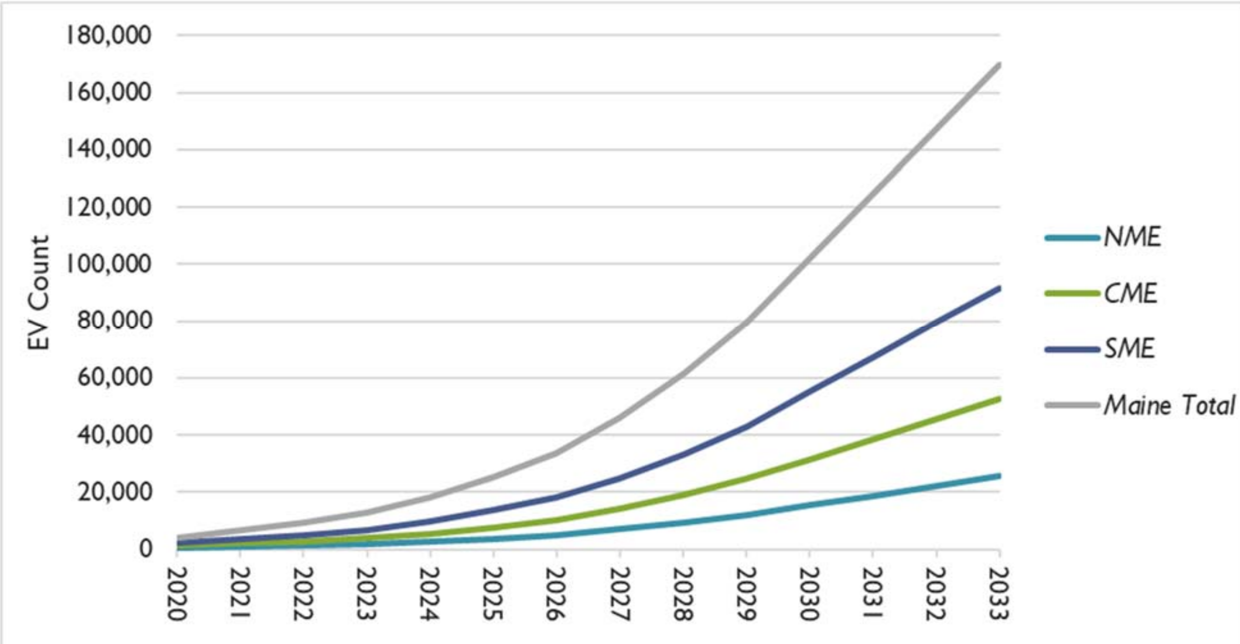
Figure 25. Statewide electric LDV adoption in High, Medium, and Low scenarios



To disaggregate the statewide forecast into the three subareas, we calculated each subarea's share of EV types using historical vehicle registration data.[61] Specifically, we estimated incremental EV counts by county from 2022 to 2023 as a proxy for EV sales, calculated county- and subarea-level sales shares, and held these shares constant over the analysis period. Figure 26 shows our Medium-scenario forecasts of electric LDVs by subarea.

[61] Historical vehicle registration data available at: https://www.maine.gov/dep/air/mobile/vehicle-data.html.

Figure 26. Statewide electric LDVs adoption by subarea in Medium scenario



These forecasts capture an estimate of the number of EVs likely to be registered in Maine in 2033, but they do not account for the impacts of EVs driven by visitors to Maine. According to the Maine Office of Tourism's (MOT) *2024 Summer Visitor Tracking Report*, Maine received 7.8 million visitors in the summer of 2024, 78 percent of whom drove.[62] To understand the impact of visiting vehicle charging on Maine's overall EV charging load, Synapse used the MOT summer and winter regional reports to forecast the number of EVs driven by visitors to the state.

MOT's seasonal visitor tracking reports provide data including regional visitor counts, visitor origin, average trip length, and average travel party size.[63] Synapse used this data to derive an estimated number of daily vehicles driving into Maine from the total number of seasonal visitors for each tourism region, which we then aggregated up to the subarea level. Based on our professional judgement, we adjusted the daily vehicle count down by 70 percent to remove weekend-only visitors because our analysis focuses on peak days, which occur during the work week. Then, using national EV adoption forecasts from BloombergNEF, we estimated the share of weekday-only visitors that are driving to Maine in battery electric and plug in hybrid vehicles.[64] Based on previous MOT reports, our analysis assumes that the number of visitors and the proportion of drivers stay constant over the forecast years.

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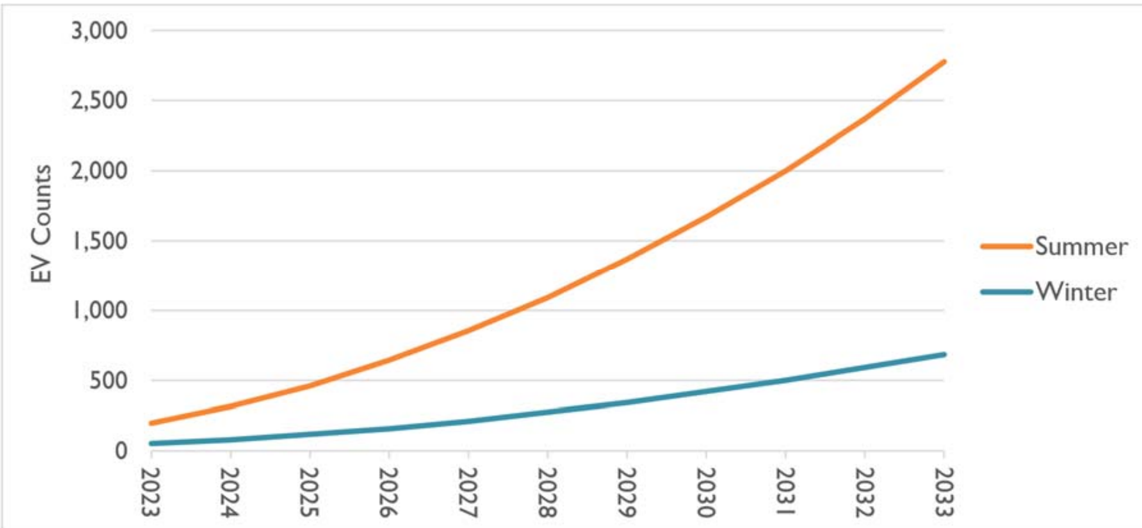
[62] Downs & St. Germain Research. 2024. "Maine Office of Tourism 2024 Summer Visitor Tracking Report May—August 2024." Slides 9 and 35. Prepared for the Maine Office of Tourism. Available at: https://motpartners.com/wp-content/uploads/2024/10/Maine-Office-of-Tourism-May-2024-August-2024-Visitor-Tracking-Report.pdf.

[63] Ibid.

[64] BloombergNEF. 2024. *"The State of the EV market." Slide 32.* Available at: https://electrificationcoalition.org/wp-content/uploads/2024/10/State-of-EV-Market-2024_10_11.pdf.

Since our High, Medium, and Low scenarios rely on state specific rebates, visitor EV adoption rates do not change between the different scenarios modeled. This results in a 2 percent increase in the number EVs charging in Maine in 2033. Figure 27 below shows the statewide number of electric LDVs visiting on weekdays for the summer and winter seasons.

Figure 27. Statewide weekday visitor EV counts



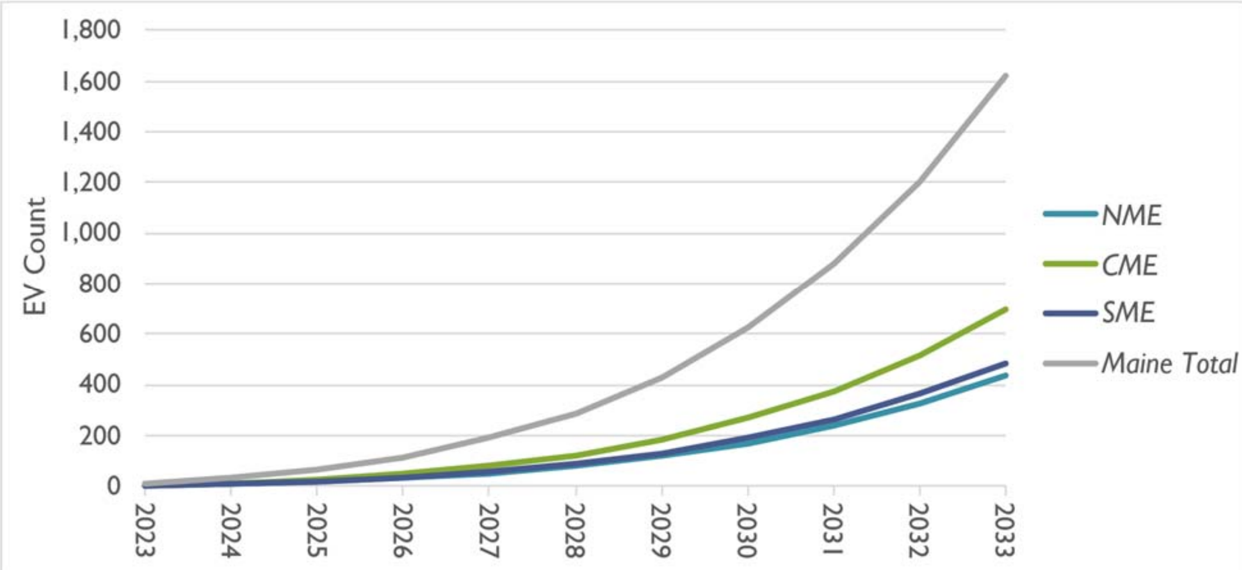
Medium- and heavy-duty vehicles

Our EV adoption model for MDV/HDV forecast relies on ISO-NE's 2025 CELT report.[65] In the 2025 CELT report, ISO-NE revised its EV adoption forecasts down compared to the 2024 CELT by calibrating to recent EV adoption rates in each state. We utilize the ISO's latest forecast for electric MDV/HDV without any modification and assume no changes to the stock forecast between the three scenarios. We then disaggregated the statewide forecast down into the three subareas based on the proportion of each vehicle type in each subarea from the historical vehicle registration data (all vehicle types).

Figure 28 shows electric MDV/HDV adoption trends over our study period by subarea, which are much lower than the LDV adoption trends shown in Figure 25, representing only about 1 percent of EVs projected in Maine in 2033 under the Medium scenario. While the charging impact from an individual electric MDV/HDV is an order of magnitude greater than the impact from an individual electric LDV, the overall peak impact from all electric MDV/HDVs is still expected to be considerably lower than the impact of LDVs. This is discussed in more detail below.

[65] ISO-NE. 2025. "Final 2025 Electric Vehicle Forecast." May 1. Slides 15-17. Available at: https://www.iso-ne.com/static-assets/documents/100023/trans_fx_2025_final.pdf.

Figure 28. Electric medium- and heavy-duty vehicle adoption by subarea



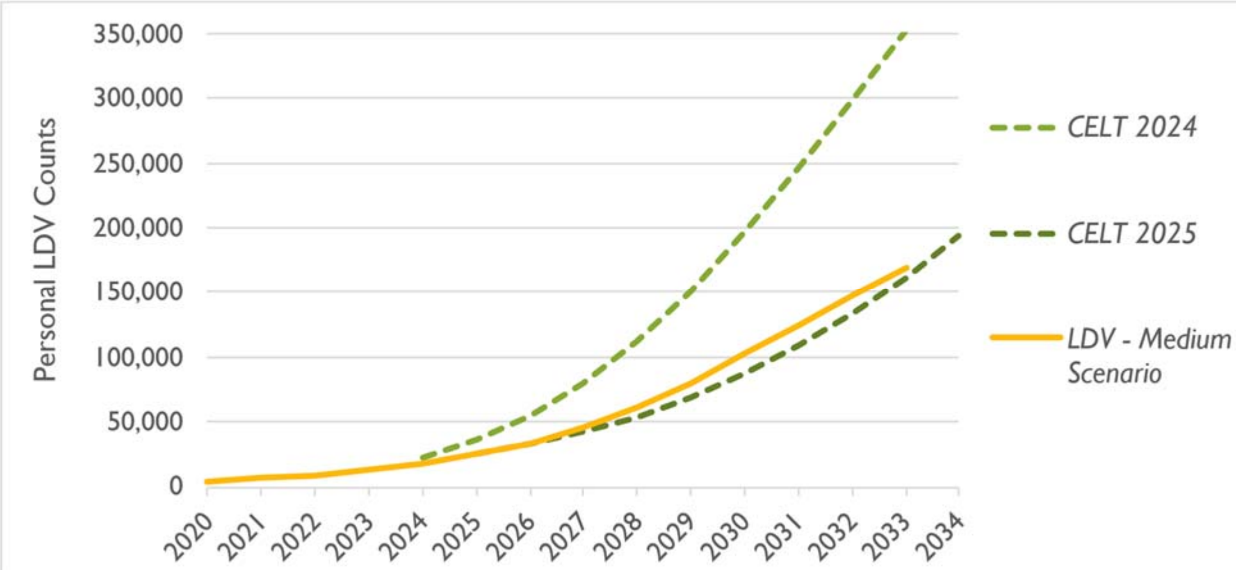
Comparison with ISO-NE's EV adoption forecast

Figure 29 provides a comparison of our EV stock forecasts for LDVs with the ISO's forecast from the 2025 CELT[66] and the 2024 CELT.[67] The 2025 CELT forecast closely aligns with our Medium scenario, while the 2024 CELT forecast is considerably higher, projecting roughly twice as many electric LDVs in 2033 compared to both our forecast and the ISO's 2025 forecast.

[66] ISO-NE. 2025. "Final 2025 Electric Vehicle Forecast." May 1. Available at: https://www.iso-ne.com/static-assets/documents/100023/trans_fx_2025_final.pdf.

[67] ISO-NE. 2024. "Final 2024 Transportation Electrification Forecast." May 1. Available at: https://www.iso-ne.com/static-assets/documents/100011/transfx2024_final.pdf.

Figure 29. Personal LDV adoption forecast under Medium scenario, compared to CELT 2024 and 2025



The 2024 CELT forecast for EVs was developed primarily based on the EV adoption targets set by the New England states, which is the primary reason the 2024 CELT forecast for EVs was considerably higher than the current forecast. In contrast, the 2025 CELT forecast is adjusted to account for recent EV adoption trends. Historical EV adoption trends compiled from vehicle registration data show that the prior CELT forecasted EV adoption exceeds the actual adoption in all states across New England.[68] The 2025 CELT forecast estimates 162,000 LDVs on the road in Maine by 2033, which is 190,000 lower than the 2024 CELT estimate and in line with our estimate of 170,000 LDVs by 2033 an shown in Figure 25 and Figure 29 above.

The updated electric MDV/HDV adoption forecast for the 2025 CELT used in our analysis is also substantially lower than the 2024 forecast. The reduced forecast reflects the availability of more comprehensive historical adoption data. The draft 2025 CELT projects approximately 415 electric MDV/HDVs in 2033, which is less than a quarter of the 2024 CELT forecast of about 1,940 electric MDV/HDVs.[69] However, this change is expected to have a very minor impact on peak demand as total electric MDV/HDV loads are much smaller than total electric LDV loads and MDV/HDV peaks do not coincide with the system peak.

Peak load impact forecast

To develop peak load impact forecasts from the annual EV adoption projections, we used daily (24-hour) vehicle energy demand profiles and charging curves corresponding to typical seasonal or monthly peak days for all vehicle types. This section first outlines the data sources and assumptions used for LDVs and

68 ISO-NE. 2024. "Final 2024 Transportation Electrification Forecast." May 1. Available at: https://www.iso-ne.com/static-assets/documents/100011/transfx2024_final.pdf.

69 Ibid.

MDVs/HDVs separately, followed by the presentation of peak load forecast results across three EV adoption scenarios.

Key assumptions and methods by vehicle type

Light-duty vehicles

For LDVs, our analysis relies on load curves for typical seasonal peak days identified in Dunsky's study, *Load Impacts from Electric Vehicles in Maine*. The study identifies three primary charging locations—public, home, and workplace—each with distinct hourly charging patterns.[70] It also provides average hourly load curves for each charging location for both summer and winter. Distinguishing between charging locations in the peak load analysis is critical to accurately capture the impacts of LDVs on peak load in Maine because typical charging behavior—and therefore hourly EV demand—is different at each location. For instance, workplace charging typically peaks during midday, while home charging typically peaks in the early evening.

In its *Load Impacts* study, Dunsky also estimated the shares of BEVs and PHEVs across different charging locations—public, home, and workplace. Our analysis assumes that these charging shares remain constant across all scenarios and subareas. However, the composition of vehicle types (i.e., the relative shares of BEVs and PHEVs) changes according to the Dunsky forecasted sales.[71] We also assume that all visiting vehicles (estimated using MOT data, as discussed above) use public charging, so the total visiting vehicles estimated for each subarea are added to the LDV public charging counts for each zone.

Once we determine the counts of each type of vehicle (BEV, PHEV) charging at each charging location (public, home and workplace), we multiply them by the seasonal 24-hour load curve for each vehicle type and location to estimate the total hourly demand for LDVs. Finally, we apply a multiplier to scale the estimated load to a 90/10 load scenario. We calculate a unique constant multiplier for each region and season combination based on ISO-NE's 2024 CELT estimates of 90/10 and 50/50 EV loads. We conducted this analysis separately for each EV forecast specific to the three subareas.

Medium- and heavy-duty vehicles

As described above, our analysis adopts the 2025 CELT's EV adoption forecast for the electric medium- and heavy-duty vehicles (MDV/HDV). To estimate peak load impacts from electric MDV/HDV, we developed hourly electricity charging estimates from the forecasted EVs using EV charging profiles from the 2024 CELT and the 2025 CELT. Specifically, we first derived the annual electricity charging estimates by MDV/HDV type for Maine from the 2024 CELT and scaled these estimates proportionally to align with

[70] Dunsky Energy and Climate Advisors. 2024. *Load Impacts from Electric Vehicles in Maine: Results Memo*. Prepared for Efficiency Maine Trust. Available at: https://www.efficiencymaine.com/docs/TPVI_Appendix_L4_Load_Impacts_EV_Maine.pdf.

[71] Dunsky Energy and Climate Advisors. 2024. *Electric Vehicle Market Assessment: Historical and Forecasted Adoption and Influence of Rebates*. Prepared for Efficiency Maine Trust. Available at: https://www.efficiencymaine.com/docs/TPVI_Appendix_L3_EV_Market_Assessment.pdf.

the 2025 CELT forecast of electric MDV/HDV. We then allocated annual charging to hourly loads during winter and summer peak months using daily charging profiles and average daily charges by month available from both CELT reports.[72] Finally, we applied the same load multiplier used for LDVs mentioned above to scale the estimated load to a 90/10 load scenario. We present MDV/HDV charging impacts separately from the load forecasts for LDV home, workplace, and public charging.

Total coincident peak load impact

Peak load impacts without managed charging

Figure 30 and Figure 31 present our Medium scenario estimates of total hourly EV load on a peak day by season in 2033, segmented by charging location and vehicle type. Home charging (blue) dominates, with most charging occurring from evening to midnight. Workplace (red), public (orange), and electric MDV/HDV (green) charging contribute more during daytime hours, with workplace charging peaking in the mid to late morning. The impact of electric MDVs and HDVs, which account for just 1 percent of EVs registered in Maine, is small in comparison to home LDV charging and peaks in the early hours of the morning. Overall, the lowest charging levels occur in the early morning (4–8 AM), while peak charging occurs in the evening (7 PM to midnight). The charging patterns are mostly similar between the seasons, although home charging ramps up earlier during the summer. On the other hand, the level of charging is much greater during the winter primarily due to the impacts of lower EV battery efficiencies during the winter; the highest EV charging loads are about 160 MW in the summer and about 260 MW in the winter.

[72] ISO-NE. 2025. "Final 2025 Electric Vehicle Forecast." May 1. Slides 22 and 23. Available at: https://www.iso-ne.com/static-assets/documents/100023/trans_fx_2025_final.pdf; and ISO-NE. 2024. "Final 2024 Transportation Electrification Forecast." May 1. Slides 20 and 21. Available at: https://www.iso-ne.com/static-assets/documents/100011/transfx2024_final.pdf.

Figure 30. Maine statewide summer 2033 peak day charging load curve Medium scenario

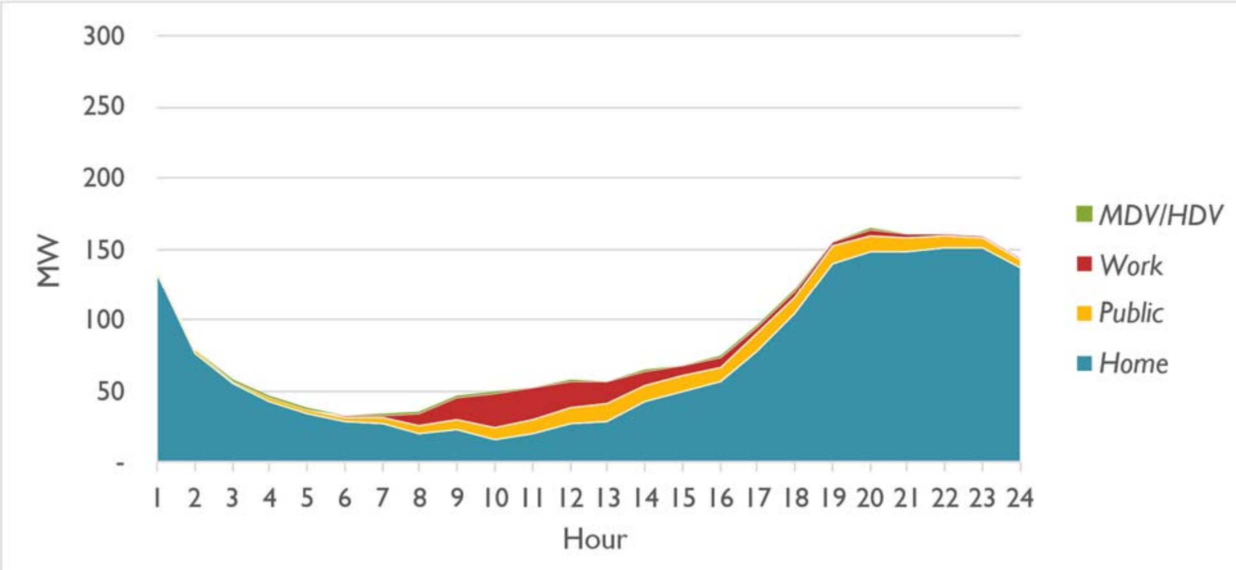
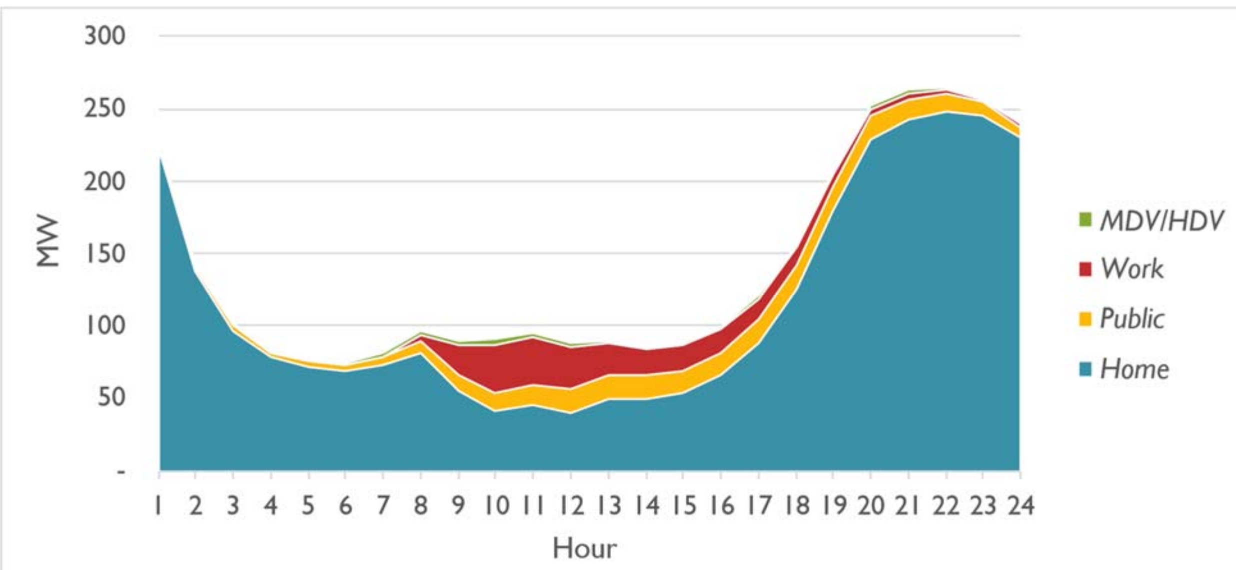
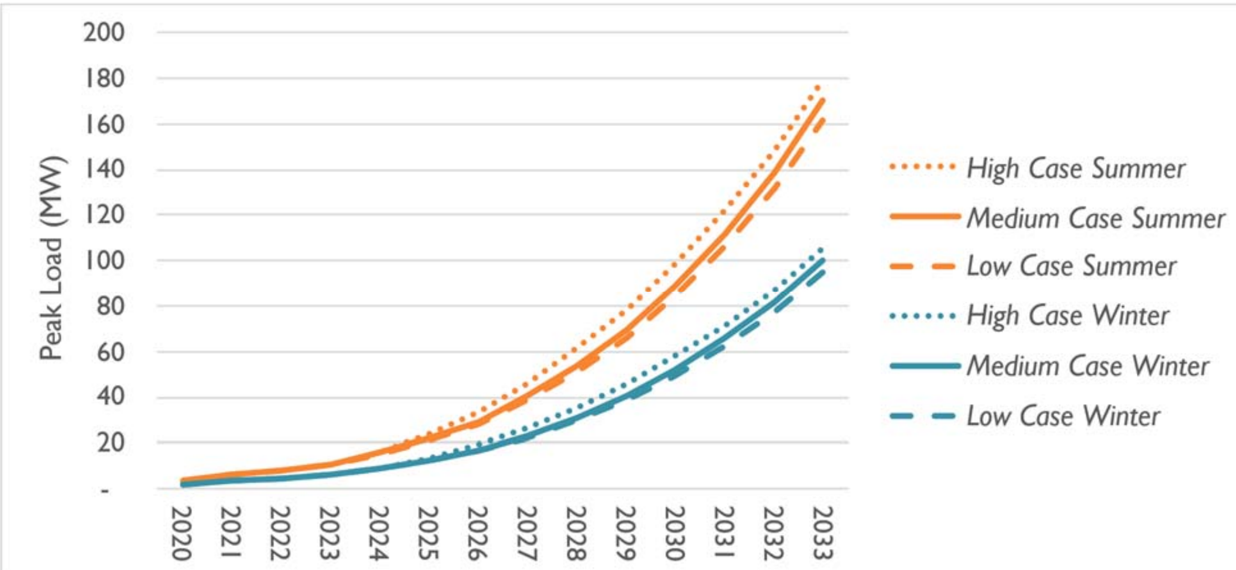


Figure 31. Maine statewide winter 2033 peak day charging load curve, Medium Scenario



The highest EV loads may not necessarily coincide with the system-wide peak loads at the subarea or statewide levels, which is the primary focus of our analysis. Thus, we reviewed coincident peak hours and estimated coincident peak loads from EVs based on the hourly load results in Figure 30 and Figure 31. In Section 2, we developed hourly loads for an extreme weather day of each season and identified the current coincident peak hours between 2 and 7 PM in summer and 8 to 10 AM in winter. Notably, the winter season also experiences a secondary peak around 6 to 7 PM, which is slightly lower than the morning peak. Looking ahead to 2033, we anticipate significant additional winter peak loads from heat pumps. While this will not affect summer peak timing, it is expected to further shift the winter peak from evening to early morning as households, businesses, and institutions begin heating buildings earlier in the day. For the purposes of our EV peak load analysis, we therefore assume the 8 AM morning peak as the potential future coincident peak hour for winter and 8 PM for summer. The peak load is scaled up to 90/10 load using unique multipliers we developed for each region and season combination, as mentioned in the previous section. We estimated coincident peak loads from EVs through 2033 for three EV adoption scenarios by season as shown in Figure 32. We expect that the total coincident peak loads will grow to approximately 161 to 179 MW in the summer and 95 to 105 MW in the winter. These estimates do not yet account for the impacts of managed charging strategies (e.g., time of use rates and load controls).

Figure 32. Maine statewide seasonal 90/10 peak EV charging load by scenario without managed charging



Note: This chart assumes that winter peak load occurs early in the morning.

<u>Peak load impacts with managed charging</u>

We applied managed charging assumptions to our initial estimates of EV charging peak load and estimated a range of potential peak load impacts from EVs for 2033. EV managed charging is a load management strategy to manage customers' EV battery charging in exchange for financial incentives for customers or to encourage customers to voluntarily modify the timing of their EV charging through time-varying rates.

EMT currently offers an EV managed program for LDVs with Level 2 chargers with 99 participants in FY2024.[73] EMT is planning to implement a DER Initiative as part of their Demand Management program for the Triennial Plan VI or FY2026-FY2028. There are two strategies for managed charging within the DER Initiative: an incentive to offset the incremental cost of a Smart Charger, and the program with

[73] Efficiency Maine Trust. 2024. *FY2024 Annual Report.* Page. 37. Available at: https://www.efficiencymaine.com/docs/FY2024-Annual-Report.pdf.

charger management via already purchased smart chargers or vehicles with telematics.[74] The non-dispatched passive smart charger initiative has demand reduction targets of 1.4 MW, 2.68 MW, and 3.37 MW for 2026, 2027 and 2028 respectively.[75] The active dispatch Open Access Charging initiative has demand reduction targets of 0.03 MW, 0.06 MW, and 0.12MW for 2026, 2027, and 2028 respectively.[76]

Our analysis assumes managed charging only for LDVs charged at home, excluding other LDV charging locations and all MDV/HDV charging. This is because public, workplace, and MDV/HDV charging are generally less flexible, and there is currently limited experience in managing charging for these use cases. We model three levels of EV managed charging for LDV home charging, corresponding to the three EV load scenarios, as shown in Table 8 below.[77] The managed charging efforts for the Low and High scenarios reflect two ends of the spectrum:

- The Low scenario assumes widespread adoption of managed charging with lower peak reductions per participant, resulting in 72 percent overall peak reductions.
- The High scenario assumes a smaller, more engaged group of participants achieving 10 percent overall peak reductions. This is consistent with the ISO's managed charging assumption of 10 percent participation by 2033 used in both the 2024 and 2025 CELT forecasts.[78]

The Low scenario is expected to yield significantly greater peak load savings due to its higher assumed participation rate. This assumption is primarily based on historical experience with opt-out time-varying rates implemented by utilities.[79]

[74] Efficiency Maine Trust. 2025. *Triennial Plan for Fiscal Years 2026-2028.* Pages. 75 – 76. Available at: https://www.efficiencymaine.com/docs/Triennial-Plan-VI_2025_4_25.pdf.

[75] Efficiency Maine Trust. 2024. *Appendix O-2 Demand Management Program Benefit Cost Analysis*. Available at: https://www.efficiencymaine.com/triennial-plan-vi/.

[76] Ibid.

[77] Our recent EV study for Minnesota titled *Charging Minnesota's Electric Vehicles – Strategies that work for the Electric Grid and Consumers,* employed similar managed charging assumptions. The study is available at: https://www.synapse-energy.com/charging-minnesotas-electric-vehicles-strategies-work-electric-grid-and-consumers.

[78] ISO-NE. 2024. "Final 2024 Transportation Electrification Forecast." Slide 27. May 1. Available at: https://www.iso-ne.com/static-assets/documents/100011/transfx2024_final.pdf; ISO-NE. 2025. "Final 2025 Electric Vehicle Forecast." May 1. Slide 24. Available at: https://www.iso-ne.com/static-assets/documents/100023/trans_fx_2025_final.pdf.

[79] Past studies have shown that opt-out time-of-use rates (one type of time-varying rate) tend to have very high participation rates (e.g., over 90 percent), but lower levels of load shifting per participant. See Environmental Defense Fund. 2015. *A Primer on Time-Variant Electricity Pricing*. Available at: https://www.edf.org/sites/default/files/a_primer_on_time-variant_pricing.pdf; Lawrence Berkeley National Laboratory (LBNL). 2023. *The use of price-based demand response as a resource in electricity system planning*. Available at: https://eta-publications.lbl.gov/sites/default/files/price-based_dr_as_a_resource_in_electricity_system_planning_-_final_11082023.pdf.

Table 8. Managed charging assumptions for LDVs in 2033

Scenario	Low	Medium	High
Peak Reduction per EV	80%	90%	100%
Participation Rate	90%	50%	10%
Total Peak Reduction	72%	45%	10%

Figure 33 and Figure 34 show the winter and summer EV peak load, respectively, under both managed and unmanaged scenarios. The unmanaged charging peaks are represented by adding the solid and hatched regions. The SME subarea (mainly Portland) has the highest regional EV charging load in both seasons due to also having the highest forecasted EV adoption. In the unmanaged scenario, winter EV peak load ranges from 51 MW to 57 MW (Figure 33), while summer peak load ranges from 88 MW to 97 MW (Figure 34). Across all scenarios, the Central Maine (CME) subarea has just over half of SME's charging demand, with winter peaks ranging from 28 MW to 31 MW and summer peaks from 49 MW to 55 MW. The NME subarea has slightly over one-quarter of SME's demand, with winter peak loads ranging from 13 MW to 15 MW and summer peak loads ranging from 23 MW to 26 MW.

The potential peak load savings by managed EV charging are shown by the hatched areas in Figure 33 and Figure 34. Since managed charging peak load reductions are estimated based on a percentage of the overall peak across scenarios, SME subarea has the highest peak savings potential from managed charging, ranging from 5 MW to 32 MW in winter and from 9 MW to 57 MW in summer. These values highlight the significant role managed charging can play in mitigating future load impacts. The relative magnitude of peak savings in the CME and NME subareas mirror the differences in their EV loads compared to Portland.

Figure 33. Winter 2033 managed charging and unmanaged charging potential 90/10 peaks

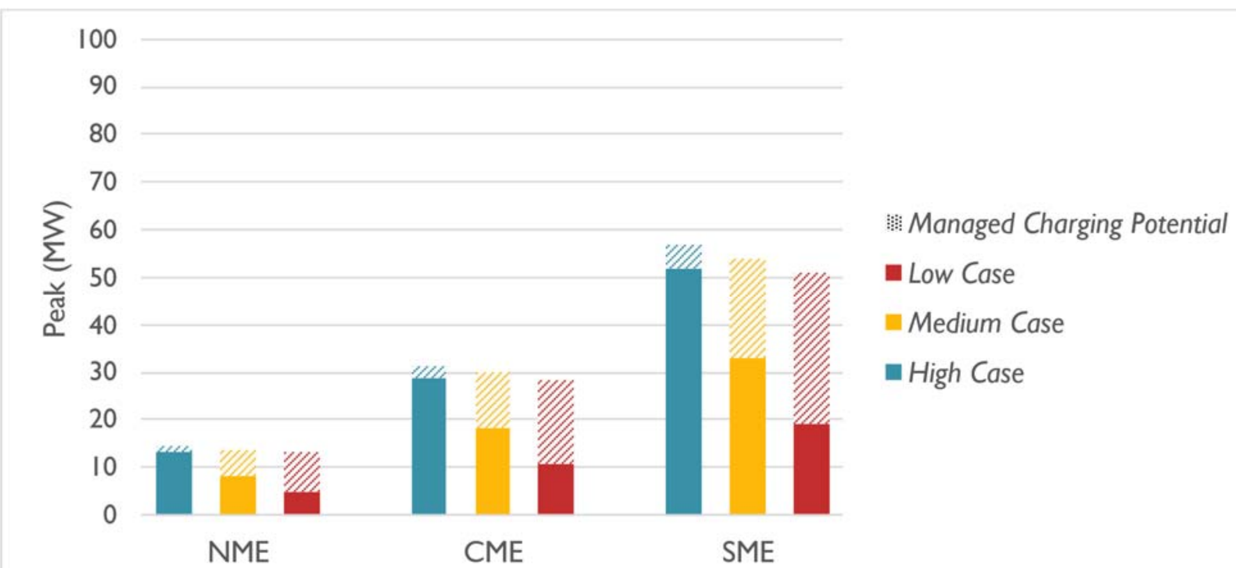
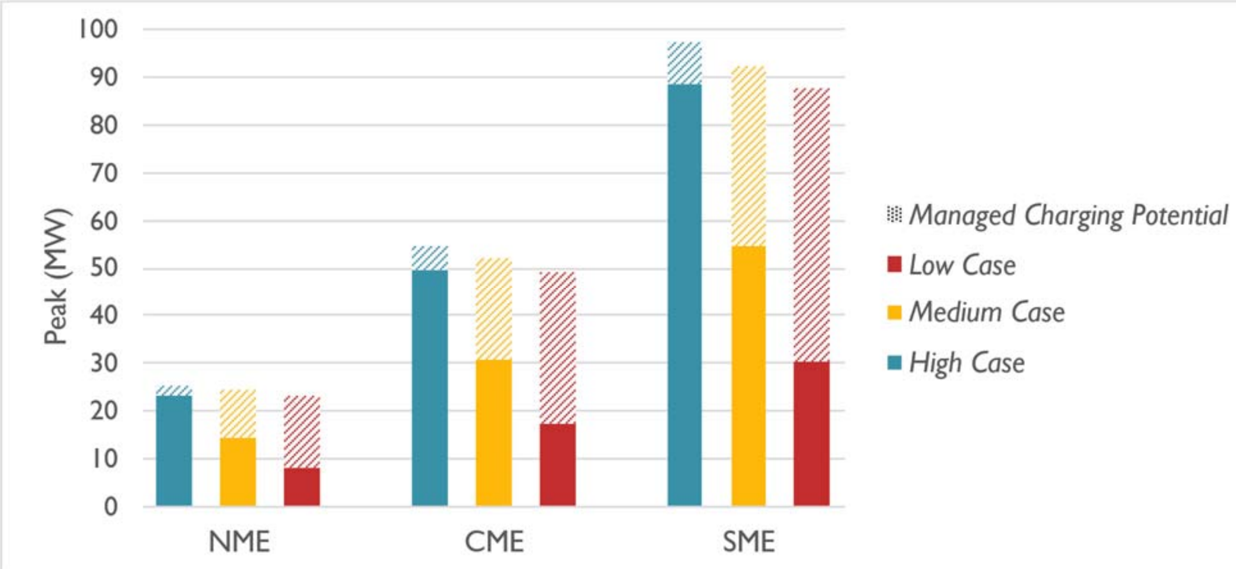


Figure 34. Summer 2033 managed charging and unmanaged charging potential 90/10 peaks



Comparison with ISO-NE's CELT forecast

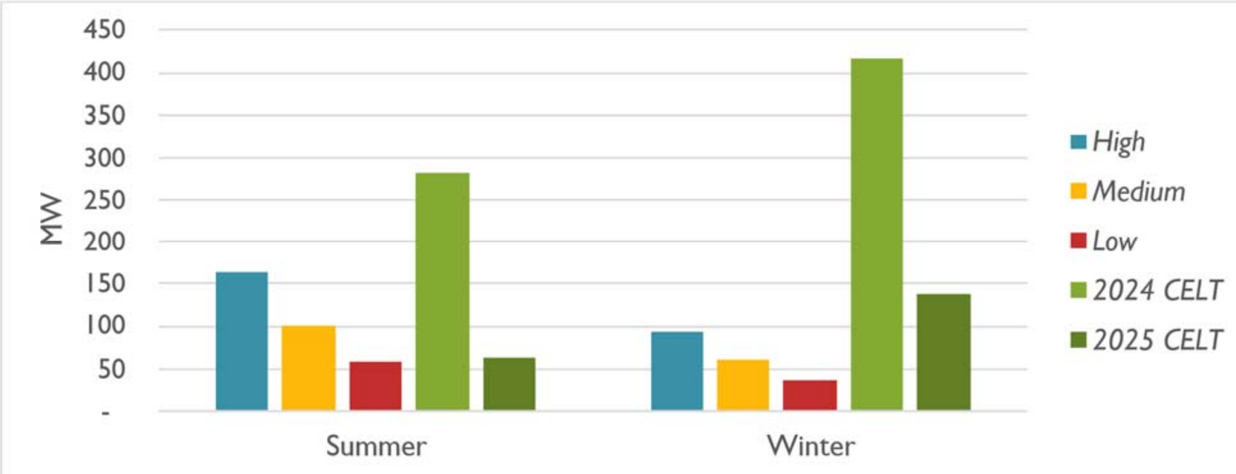
This section compares our EV peak load forecasts for the Medium scenario with those from ISO's 2024 and 2025 CELT forecasts. We focus on statewide rather than regional comparisons, as the substantial difference in EV adoption rates between our scenario and the 2024 CELT (see the EV stock forecast section) makes a statewide comparison sufficiently informative.

The 2024 CELT forecast is based on a very aggressive EV adoption scenario, resulting in inflated EV peak load estimates as shown in Figure 35 below. According to the 2024 CELT, Maine's EV load is projected to peak at 417 MW in the winter and 281 MW in the summer. These projections are approximately 3.5 to 10 times higher than our winter peak load estimates for 2033 and about 73 percent to nearly four times higher than our summer peak estimates for the same year.

ISO-NE stated that lack of historical adoption data contributed to the overestimation in the 2024 CELT vehicle forecast, which relies on state policy goals rather than actual adoption trends.[80] As a result, the 2024 CELT forecast for electric LDV adoption rates exceed our High scenario by 92 percent. For the 2025 CELT, ISO introduced a calibration step to the EV forecast methodology to incorporate historical EV adoption data. This revised methodology better reflects the gap between state adoption targets and consumer behavior. The resulting peak load forecasts are 67 percent lower for winter and 78 percent lower for summer compared to the 2024 CELT. According to the 2025 CELT, Maine's EV load is projected to peak at 138 MW in the winter and 62 MW in the summer. These projections are approximately 50 percent higher than our high-scenario winter peak load estimate for 2033 and about 9 percent lower than our low-scenario summer peak estimate for the same year.

[80] ISO New England. 2025. "Final 2025 Transportation Electrification Forecast." May 1. Slide 9. Available at: https://www.iso-ne.com/static-assets/documents/100023/trans_fx_2025_final.pdf.

Figure 35. Statewide 90/10 EV peak load with managed charging in 2033, and comparison to ISO-NE 2024 CELT and 2025 CELT



In addition to differences in EV adoption rates, a key factor contributing to the higher winter peak load impacts in the 2024 and 2025 CELT forecasts is the assumed hourly EV charging profiles during the morning period. Both our analysis and the CELT assume that winter system peak loads shift to the morning in future years as heating electrification increases; accordingly, differences in projected winter EV peak impacts are driven primarily by differences in assumed morning charging behavior, in addition to differences in EV adoption rates.[81] Our forecast assumes that the winter system peak shifts to the morning (around 8 a.m.) by 2033, while the summer peak continues to occur in the evening. As shown in Figure 30 and Figure 31, EV charging in our assumed profiles peaks in the late evening and is largely completed by early morning, resulting in relatively low EV contributions to early-morning winter peaks. In contrast, the CELT's assumed hourly charging profiles for electric LDVs include a secondary charging peak around 10 a.m.[82] This morning EV peak exceeds half of the evening EV peak load. By comparison, in our assumed charging profiles (Figure 31), the highest morning EV load is approximately 35 percent of the evening EV peak load.

The 2025 CELT projects EV adoption rates for 2033 that are approximately half of those in the 2024 CELT (see Figure 29), yet its peak load forecasts are less than half of the prior year's estimates. The winter EV peak load forecast in the 2025 CELT is closer to our High scenario forecast than CELT 2024, which assumes similar levels of EV adoption and managed charging. However, the 2025 CELT winter peak

[81] ISO-NE. 2024. "CELT 2024: Heating electrification will drive higher energy use, winter peaks." May 9. Available at: https://isonewswire.com/2024/05/09/celt-2024-heating-electrification-will-drive-higher-energy-use-winter-peaks/; ISO-NE. 2025. "Final 2025 Electric Vehicle Forecast." May 1. Slide 30. Available at: https://www.iso-ne.com/static-assets/documents/100023/trans_fx_2025_final.pdf.

[82] ISO-NE. 2024. "Final 2024 Transportation Electrification Forecast." May 9. Slide 20. Available at: https://isonewswire.com/2024/05/09/celt-2024-heating-electrification-will-drive-higher-energy-use-winter-peaks/; ISO-NE. 2025. "Final 2025 Electric Vehicle Forecast." May 1. Slide 22. Available at: https://www.iso-ne.com/static-assets/documents/100023/trans_fx_2025_final.pdf.

remains approximately 50 percent higher than our estimate, as mentioned above. This is likely due to ISO's continued assumption—similar to the 2024 CELT—that the winter coincident peak occurs in the early evening (e.g., 8 p.m.), when other end-use loads are significantly higher than in the early morning. In contrast, our High-scenario summer peak forecast is more than double the 2025 CELT summer forecast, despite similar assumptions on EV adoption rates and managed charging. This discrepancy may stem from ISO-NE assuming lower per-vehicle peak consumption during the summer, as well as potentially different assumptions about the timing of the coincident peak hour.

3.3. Other resources

This section summarizes our approach to developing our peak load forecasts for BTM PV, EE, and demand response.

BTM PV

ISO-NE's forecasting process for PV occurs in two steps. First, ISO-NE estimates the total amount of distributed PV in each region. Second, it categorizes the distributed PV into three groups: (1) Forward Capacity Market participants, (2) energy-only resource participants, and (3) non-market participants (referred to as behind-the-meter or BTM).[83]

In the 2025 CELT, ISO-NE substantially updated its BTM PV forecast to reflect Maine-specific policy changes which reduced projected solar development compared to the 2024 CELT. These changes were summarized by Ethan Tremblay of the Governor's Energy Office in a meeting with ISO-NE in December 2024.[84] The most significant policy change modeled was the requirement that all Net Energy Billing "kWh" projects must reach commercial operation by December 31, 2024, with only much smaller projects able to participate in 2025 and beyond.[85]

After forecasting the total amount of PV installed in the state, ISO-NE then calculates the amount of PV which acts as a system load reducer by subtracting market-participating PV from the total amount of forecast PV.[86] The remaining capacity represents BTM PV which reduces system load.

Synapse adopts the BTM PV forecast developed by ISO-NE as it reflects recent local policy changes. Figure 36 shows the forecast of annual energy production by region for BTM PV from CELT 2025.

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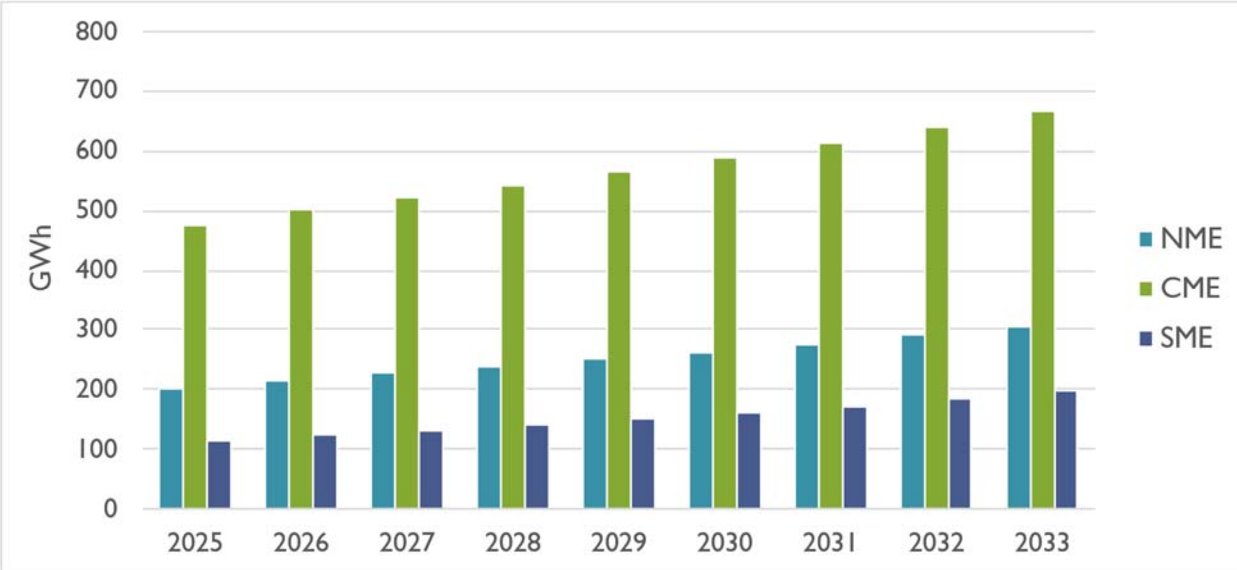
[83] ISO-NE. 2024. "Final 2024 Photovoltaic (PV) Forecast." March 25. Slide 5. Note, the ISO-NE's usage of the term BTM is more akin to non-market participant. That is, the physical metering of the device does not necessarily need to be "behind-the-meter" but the PV contributed by those panels will be referred to as BTM in ISO-NE's load forecast.

[84] Ethan Tremblay, Maine Governor's Energy Office. 2024. *Presentation to the ISO-New England Distributed Generation Forecast Working Group,* December 9. Available at: iso-ne.com/static-assets/documents/100018/me-dgfwg-12092024.pdf.

[85] ISO-NE. 2025. "Final 2025 Photovoltaic (PV) Forecast." March 24. Slide 13. Available at: iso-ne.com/static-assets/documents/100021/2_2025_final_pv_forecast.pdf.

[86] Id. Slide 27.

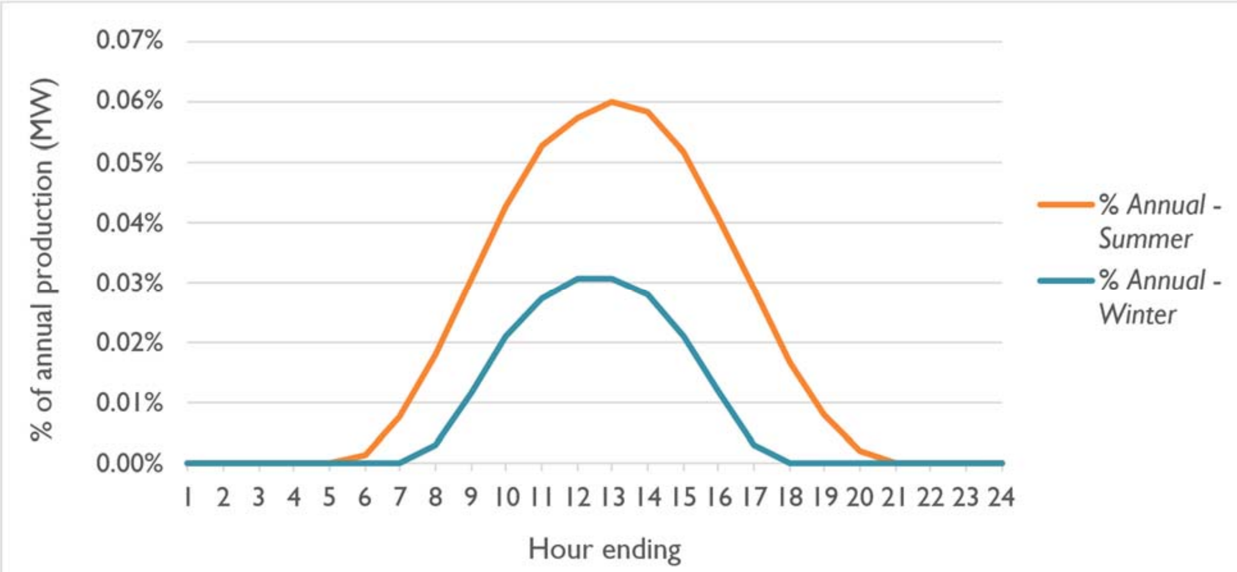
Figure 36. BTM PV annual energy forecast by region



We used CELT's annual energy forecast to develop our own estimates of peak BTM PV production using hourly production curves, since the peak hours in our analysis may differ from ISO-NE's modeling. To estimate the PV production shapes, we used historical estimates of total hourly BTM PV production in each load zone.[87] For the summer and winter peak days that we identified through our review of the total combined regional hourly loads in our analysis, we developed hourly production curves. To account for day-to-day weather variability and avoid reliance on a single day, we calculated hourly average BTM PV production across the peak month and developed peak-day hourly production profiles as shown in Figure 37.

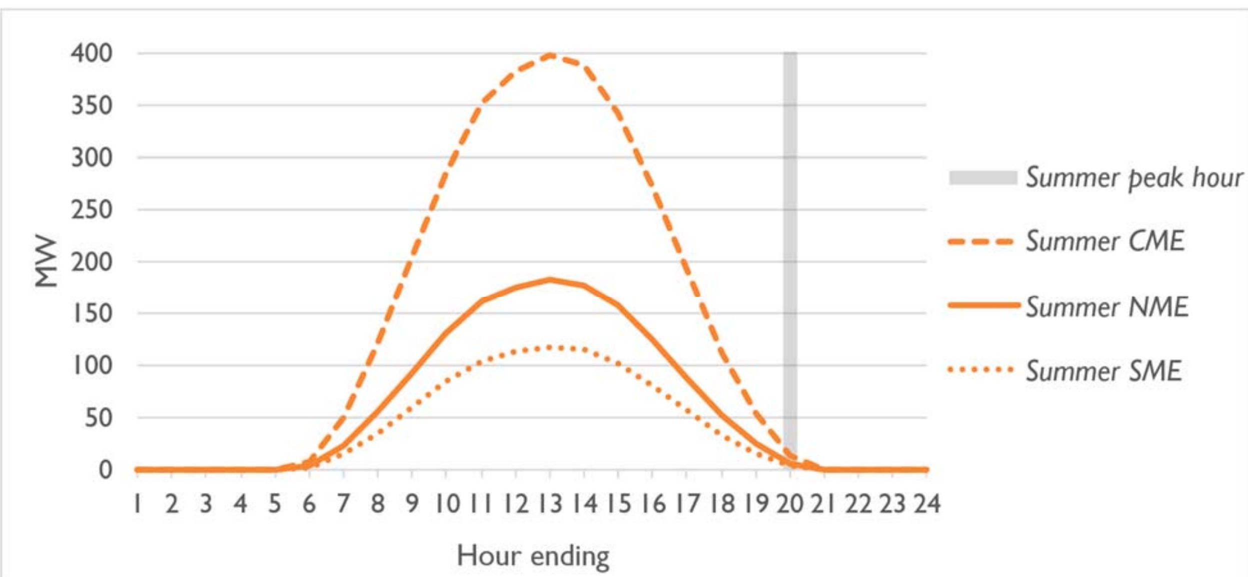
[87] ISO-NE. 2025. "Behind-the-Meter PV Data." November 20. Available at: https://www.iso-ne.com/system-planning/system-forecasting/load-forecast.

Figure 37. Summer and winter peak day BTM PV production as a share of annual production



We then applied the summer and winter statewide production shape to the annual BTM energy production by subarea from the CELT 2025 forecasts. As shown in Figure 38, in 2033, summer BTM PV production reaches its maximum in the middle of the day (1 PM) in June. However, based on our regional load analysis, the system electric peak hour occurs at 8 PM in the evening, when solar production is a fraction of its maximum.

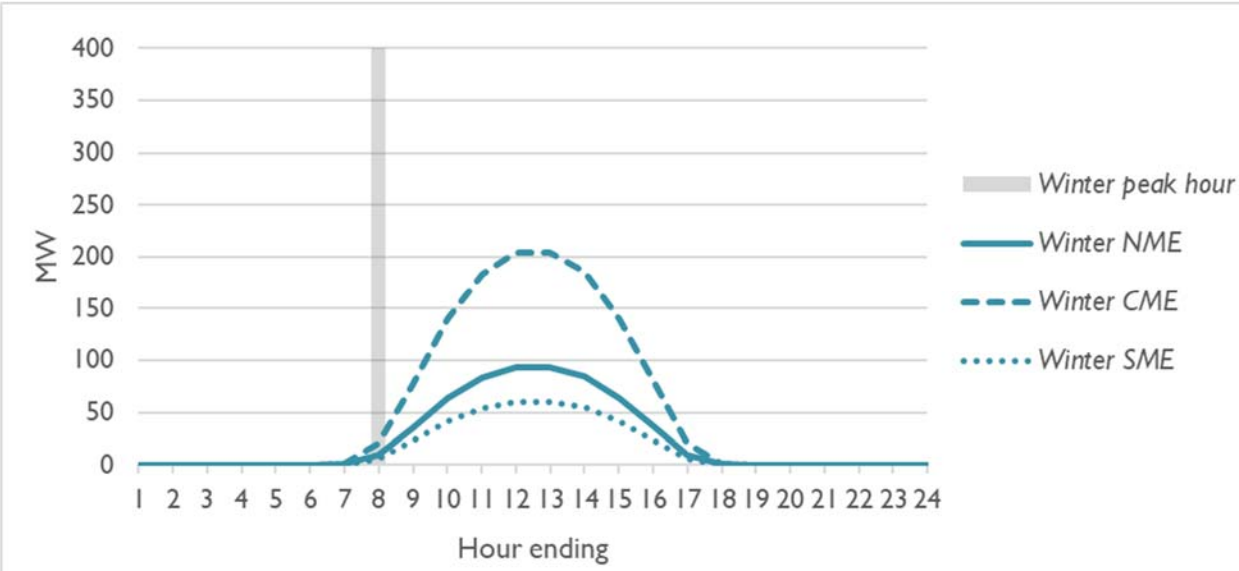
Figure 38. Summer peak day BTM PV production by subarea, 2033



Similarly, as shown in Figure 39, winter BTM PV production is at its highest in the middle of the day (at noon) in February. The system electric peak occurs at 8 am, when BTM PV production is only 10 percent of the maximum. Total winter energy from BTM PV is less than half of the summer peak day energy.

However, because the summer peak hour occurs so late in the evening, BTM PV contributions (i.e., reductions) of total peak load are greater in the winter peak hour than the summer peak hour.

Figure 39. Winter peak day BTM PV production by subarea, 2033



Energy Efficiency

As of the 2025 CELT, ISO-NE incorporates load reductions from EE directly in the conventional load forecast and therefore did not produce a separate EE forecast in 2025.[88] ISO-NE includes both historical and forward-looking EE impacts in its modeling. Thus, since we rely on the 2025 CELT conventional load forecasts, we likewise did not develop a separate EE forecast for this report.

Demand response

We incorporate demand response and storage in our peak load forecasts based on ISO-NE's 2025 CELT report. Our load forecast adjustments focus on Active Demand Capacity Resources, which respond to dispatch signals from ISO-NE. These resources represent load reductions that participate in ISO-NE's Forward Capacity Market.[89] Accordingly, we reduce our peak load forecast by the amount of cleared active demand capacity resources.

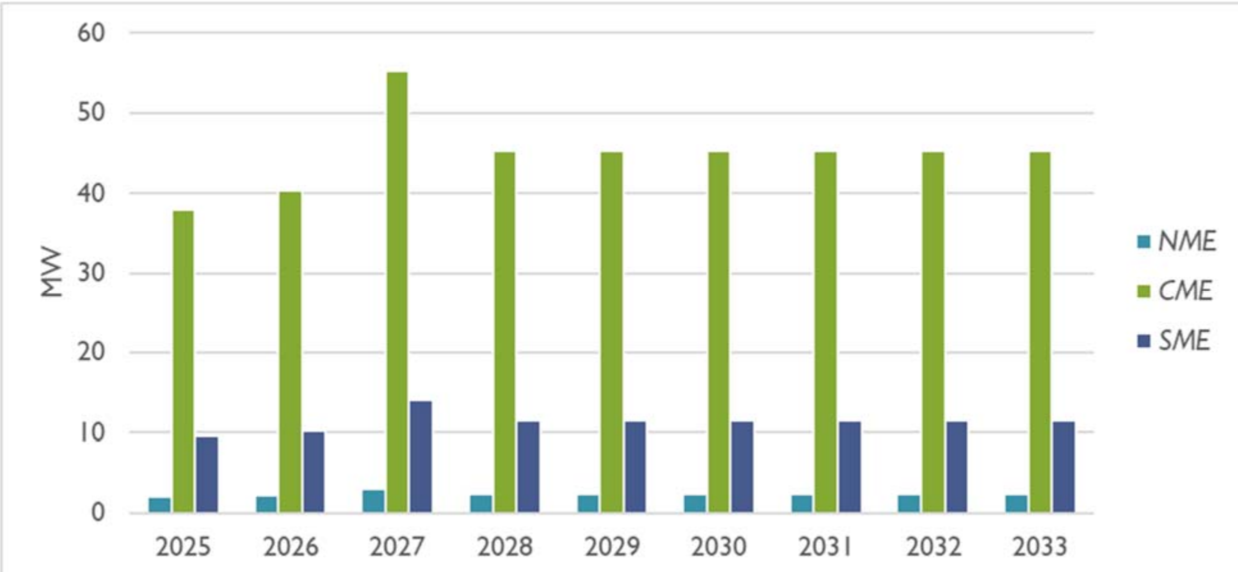
The 2025 CELT provides a forecast of active demand capacity resources for both summer and winter and load dispatch zone based on the most recent Forward Capacity Market auction, FCA 18 for the 2027/2028 capacity commitment period, as well as previous auctions. The amount of response in the

[88] ISO-NE. 2024. "Energy-Efficiency Forecast Process Changes for CELT 2025." September 30. Available at: https://www.iso-ne.com/static-assets/documents/100015/eef2025-intro.pdf.

[89] ISO-NE. n.d. "About Demand Resources." Available at: https://www.iso-ne.com/markets-operations/markets/demand-resources/about.

summer and winter is nearly identical.[90] We estimate the impact of Active Demand Capacity Resources by load zone using this information, as shown in Figure 40.

Figure 40. Forecast cleared active demand capacity resource by Maine load zones



Additionally, there are other demand response resources, such as Efficiency Maine's battery programs, that do not participate in the energy or capacity market. For the 2026-2028 Triennial Plan, EMT estimates approximately 7 MW of battery storage across the state.[91] ISO-NE refers to these resources as BTM resources. The 2025 CELT accounts for the impacts of BTM storage resources in the base load forecast.[92]

Lastly, this section excludes a few demand response measures. As discussed in the prior EV section, the impacts of EV managed charging are already captured in our EV load forecast and are therefore excluded from our estimate of demand response capacity. In addition, our analysis does not cover any demand response measures associated with electric space heating or water heating, as programs targeting these end uses are currently not implemented or planned in Maine.

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[90] ISO-NE. 2025. "2025 CELT Report" file, "4.3 Qualified, Cleared Capacity" tab, May 6. Available at: https://www.iso-ne.com/system-planning/system-plans-studies/celt.

[91] EMT. 2024. *Appendix O-1: Demand Management Program Analysis and Considerations* (part of Efficiency Maine Triennial Plan VI, FY 2026-2028). Available at: https://www.efficiencymaine.com/docs/TPVI_Appendix_O1_Demand_Management_Program_Analysis_and_Considerations_11-24.pdf

[92] ISO-NE. 2025. "DER Storage Update." Slide 12. Available at: iso-ne.com/static-assets/documents/100021/der_storage_updates_final.pdf.

4. REGIONAL LOAD FORECASTS

This section summarizes our approach to developing total regional load forecasts for Maine based on the load component forecasts from Section 2 and Section 3.

4.1. Overall peak load forecast by subarea

We combine the conventional load forecasts (Section 2) with the load component forecasts (Section 3) for the peak day in each region: NME, CME, SME.

We estimated annual peak loads through 2033 under three EV and heat pump adoption scenarios, as shown in Figure 41, Figure 42, and Figure 43. In the NME and CME regions, net summer peak loads (including reductions from BTM PV) are already lower than the winter peak loads, while in the SME region, summer peak loads are projected to be surpassed by winter peak loads around 2028. Across regions, we expect total summer peak loads to grow by approximately 10–17 percent by 2033, corresponding to increases of 33–46 MW in NME, 105-133 MW in CME, and 82–132 MW in SME. In contrast, we expect winter peak loads to increase much more rapidly. By 2033, winter peak growth ranges from 21–53 percent in the Low scenario, 30–70 percent in the Medium scenario, and 53–101 percent in the High scenario. The largest increases occur in NME, where winter peaks rise by 169 MW in the Low scenario to 338 MW in the High scenario. This growth is primarily driven by heating electrification, with relatively small contributions from transportation electrification.

Figure 41. Winter and summer peak loads by scenario through 2033, NME

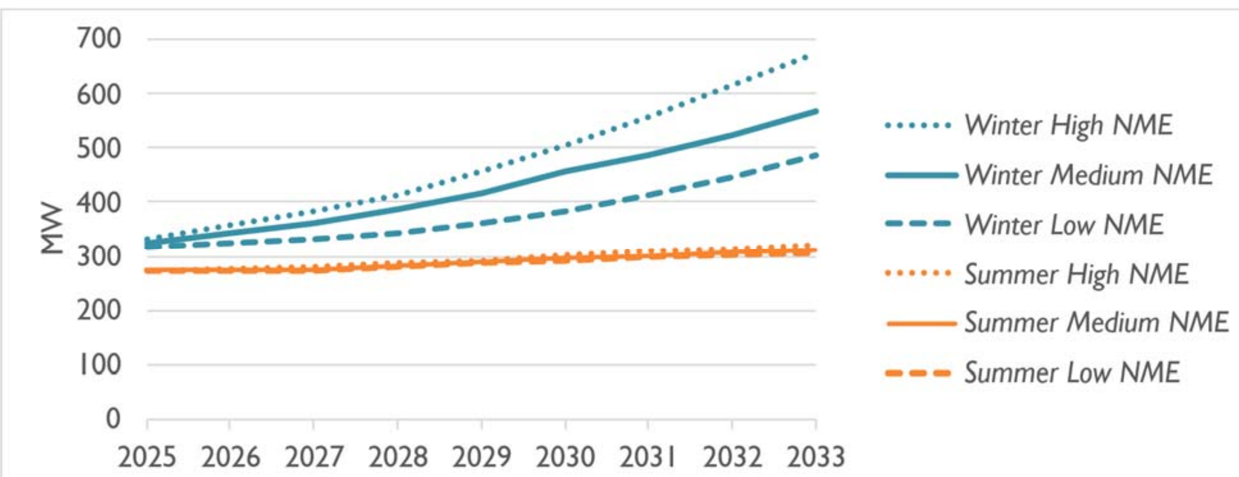


Figure 42. Winter and summer peak loads by scenario through 2033, CME

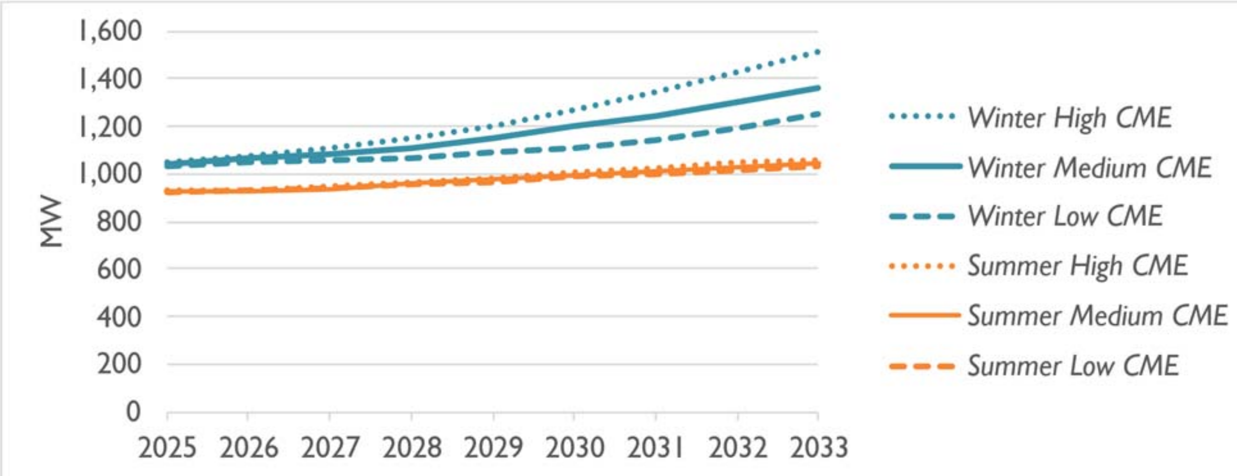


Figure 43. Winter and summer peak loads by scenario through 2033, SME

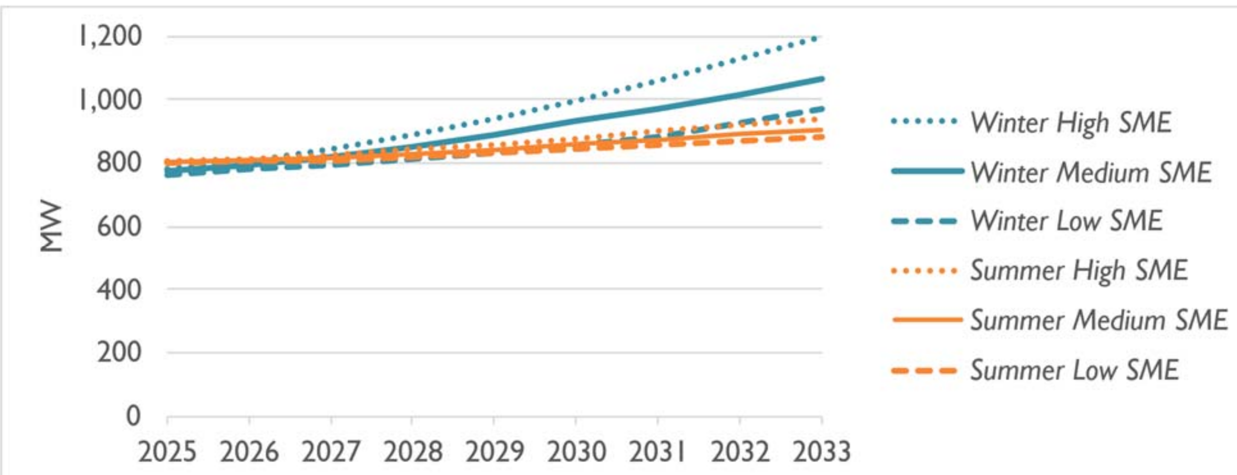


Figure 44 shows the total winter peak load by component for SME annually through 2033 under the Medium scenario. Total winter peak demand reaches 1,066 MW in 2033 in this scenario and region, a 38 percent increase from 2025. Increased demand due to heating electrification is the primary driver of winter peak increases, accounting for 29 percent of total winter peak demand in 2033. Transportation electrification is a relatively small share of winter peak, accounting for approximately 3 percent of total winter peak demand in 2033.

Figure 44. Annual winter peak load by load component for the Medium scenario, SME

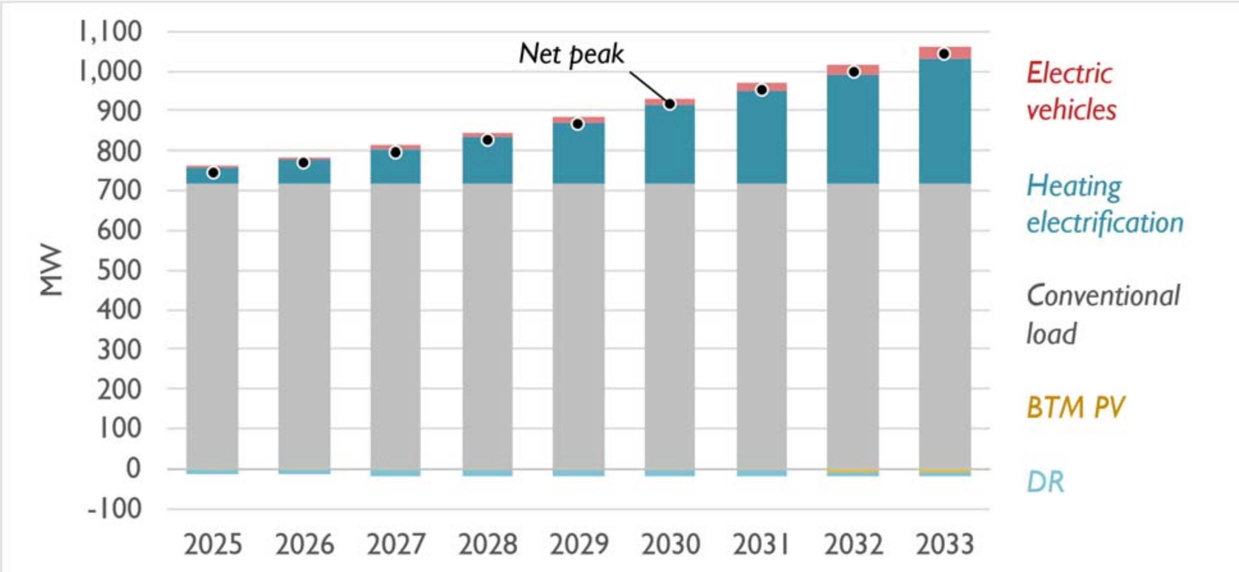
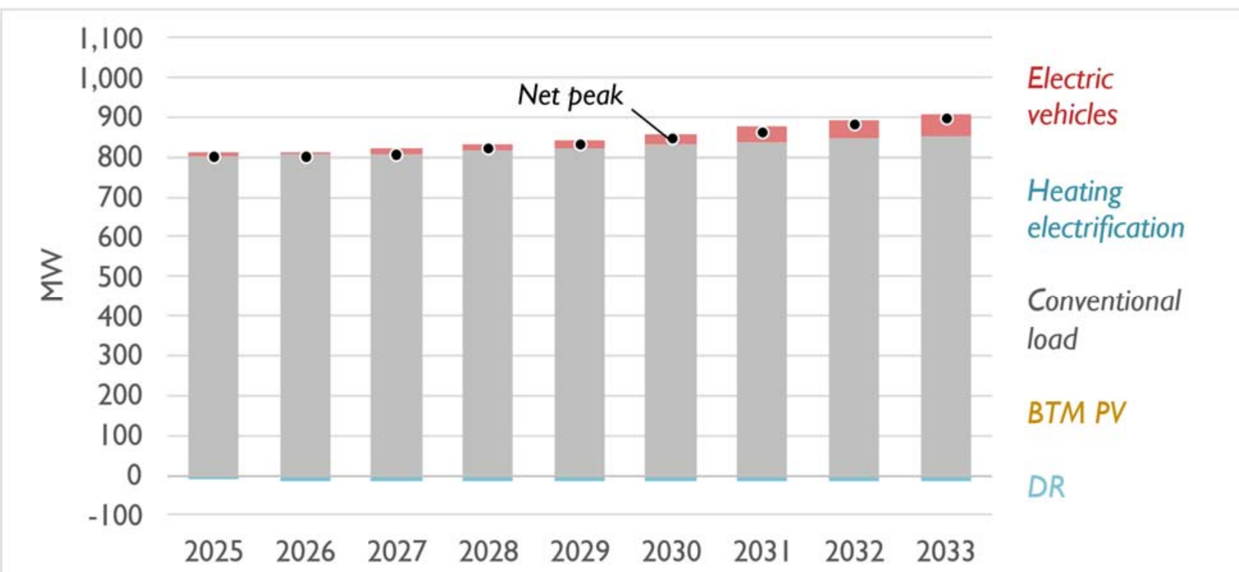


Figure 45 similarly shows the total summer peak load by component for SME annually under the Medium scenario. Overall peak growth is smaller in summer than in winter: total summer peak load increases to 907 MW, representing only a 13 percent increase from 2025, driven equally by transportation electrification and growth in conventional loads. Electric vehicle charging accounts for approximately 6 percent of the total peak demand in 2033.

Figure 45. Annual summer peak load by load component for the Medium scenario, SME



4.2. 2033 peak load forecast

Figure 46 shows total winter coincident peak loads in 2033 by component, scenario, and region. Across scenarios, winter peak loads range from 484 to 667 MW in NME, 1,265 to 1,526 MW in CME, and 957 to 1,187 MW in SME. Relative to 2025 levels, these ranges represent 60 to 100 percent increases in NME, 24 to 47 percent increases in CME, and 28 to 55 percent increases in SME.

Figure 46. Winter coincident peak load in 2033, by scenario and region

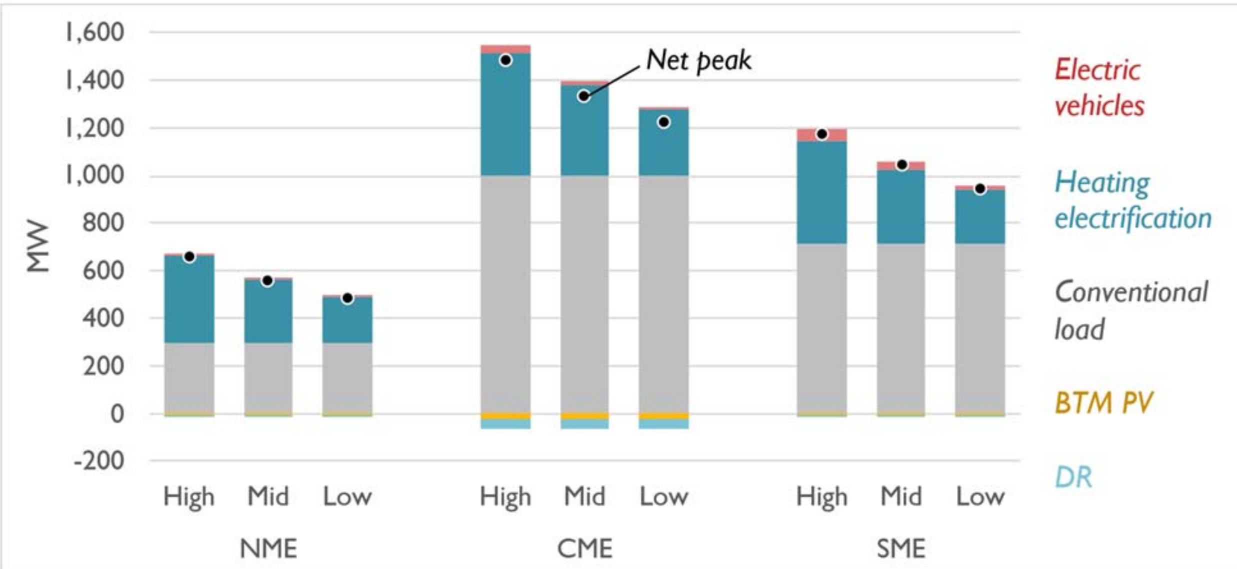


Figure 47 shows the total 2033 summer coincident peak loads by component, scenario, and region. The peak load ranges from 327 to 342 MW by scenario in NME, 1,030 to 1,063 MW in CME, and 883 to 941 MW in SME. Overall, the 2033 peak loads are 8 to 12 percent increase compared to 2025 peak loads.

Figure 47. Summer coincident peak load in 2033, by scenario and region

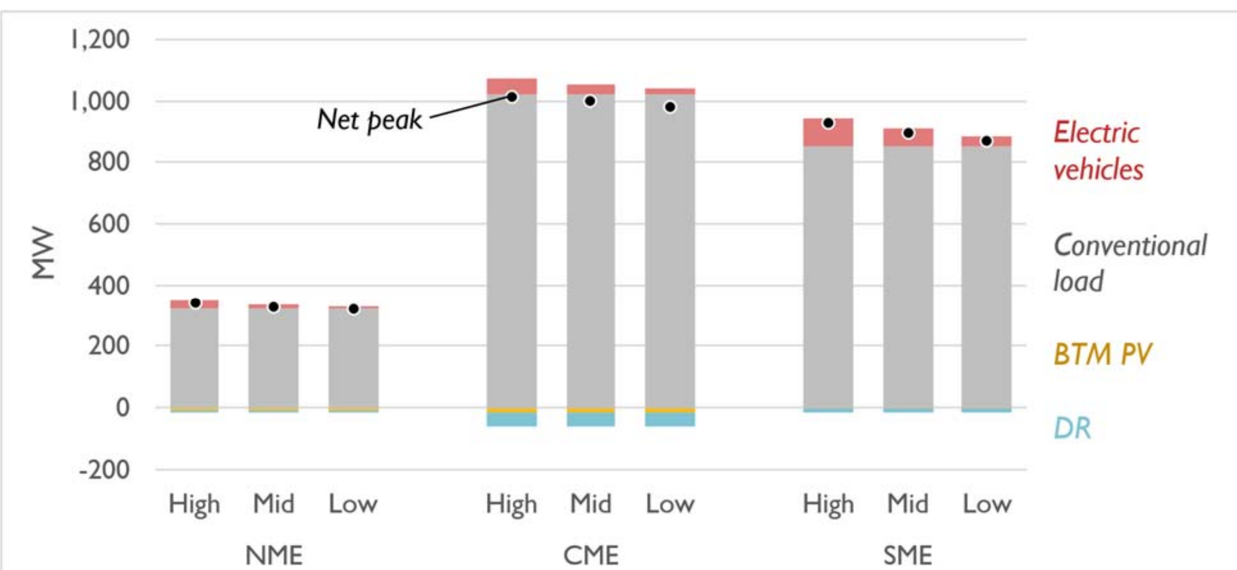


Figure 48 shows an hourly snapshot of hourly peak demand by load component for the winter peak day in 2033 under the Medium scenario in SME. The conventional load has a peak of a round 9 AM. However, the total coincident peak hour, driven by heating electrification load, is 8 AM. The net load curve in (dotted black line) shows the impact of BTM PV, which reduces total load between the hours of 8 am and 5 pm, with a maximum reduction of 60 MW around midday.

Figure 48. Hourly winter peak demand by load component in 2033 under the Medium scenario, SME

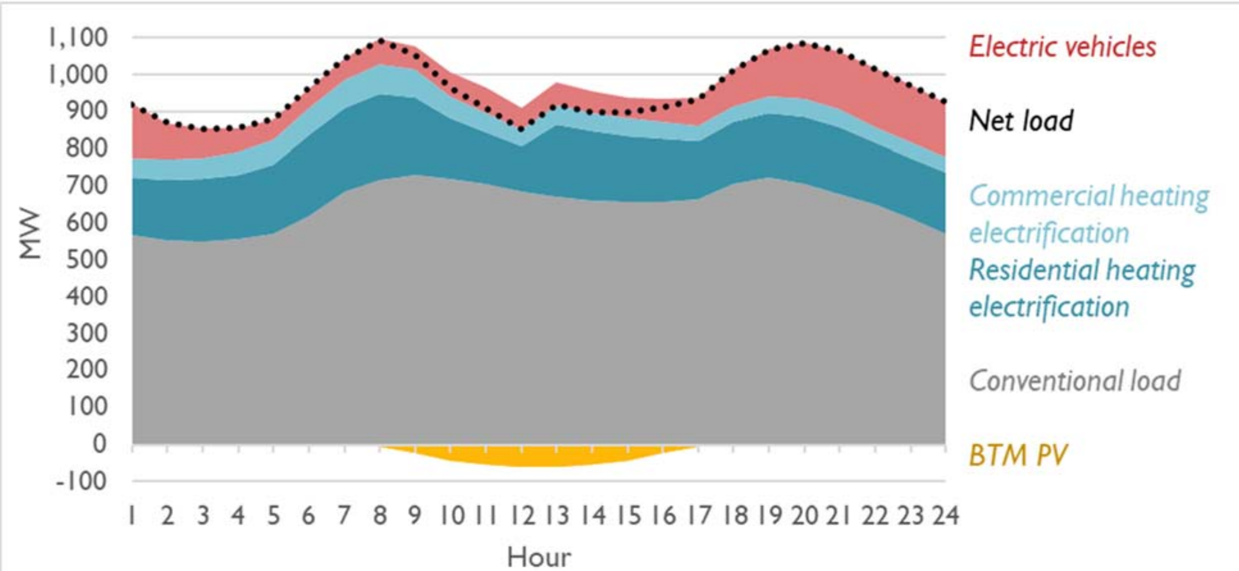
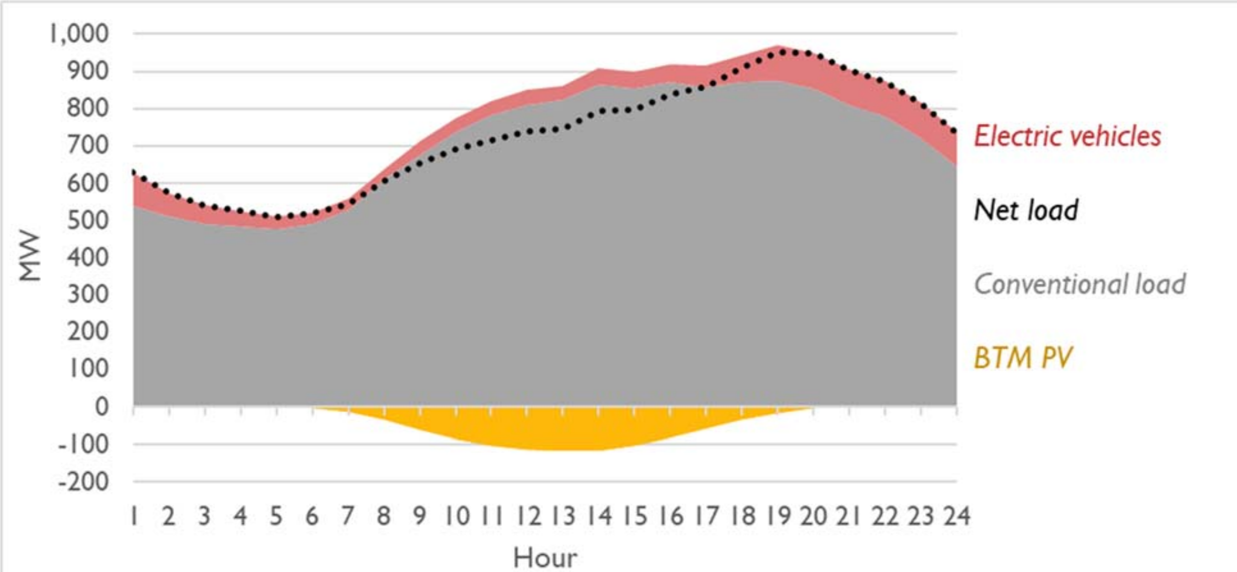


Figure 49 shows hourly peak demand by load component for the summer peak day under the Medium scenario in SME. The coincident peak hour occurs at 7 PM, primarily driven by new EV loads, while the conventional load peaks occur from 2 pm through 7 pm. The net load curve in (dotted black line) shows the impact of BTM PV, which reduces total load between the hours of 6 am and 8 pm, with a maximum reduction of 118 MW in the middle of the day.

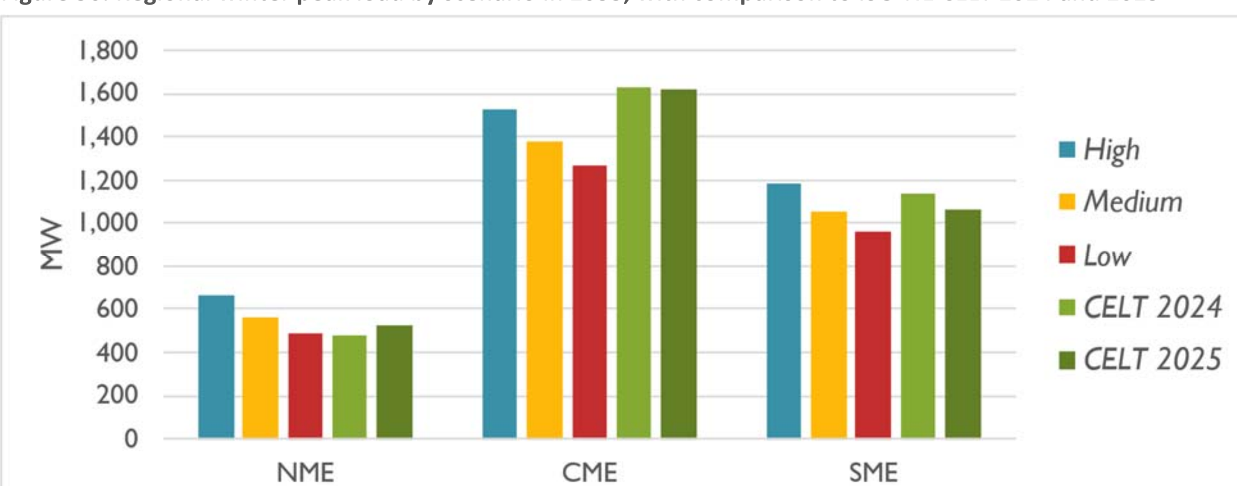
Figure 49. Hourly summer peak demand by load component under the Medium scenario, SME



4.3. Comparison with ISO-NE's CELT 2024 and 2025

Figure 50 below compares our 2033 winter peak load forecast with ISO-NE's 2024 and 2025 CELT winter forecasts by region. Relative to the 2024 CELT, the 2025 CELT projects lower winter peak loads in CME and SME, but higher winter peak loads in NME. However, the two CELT forecasts for CME are very close in magnitude. In SME, the 2025 CELT aligns closely with our Medium scenario, though it is slightly higher. In CME, however, the 2025 CELT estimate is 6 percent higher than our High scenario, and 28 percent higher than our Low scenario. In NME, the 2025 CELT estimate is 8 percent higher than our Low scenario and 7 percent and 21 percent lower than our Medium and High scenarios, respectively. By comparison, the 2024 CELT estimate for NME was 1 percent lower than our Low scenario and 28 percent lower than our High scenario.

Figure 50. Regional winter peak load by scenario in 2033, with comparison to ISO-NE CELT 2024 and 2025



In the winter, these differences are primarily driven by assumptions related to heating electrification load across regions, with transportation electrification also contributing to the higher peaks in the 2024 CELT forecast, as shown in Figure 51, which compares our Medium scenario 2033 winter peak to the 2024 and 2025 CELT forecasts by load component. The largest differences are attributable to heat pumps and EVs. Relative to both CELT forecasts, we project higher heat pump loads in NME, but lower heat pump loads in CME. Differences in EV peak load assumptions between the 2024 CELT and the 2025 CELT are also substantial and contribute meaningfully to the observed variation in total winter peak loads, particularly in CME and SME. Further discussion on these differences in heating and transportation electrification demand is provided in Sections 3.1 and 3.2.

Figure 51. Regional winter peak load by component in 2033 under Medium scenario, with comparison to ISO-NE CELT 2024 and 2025

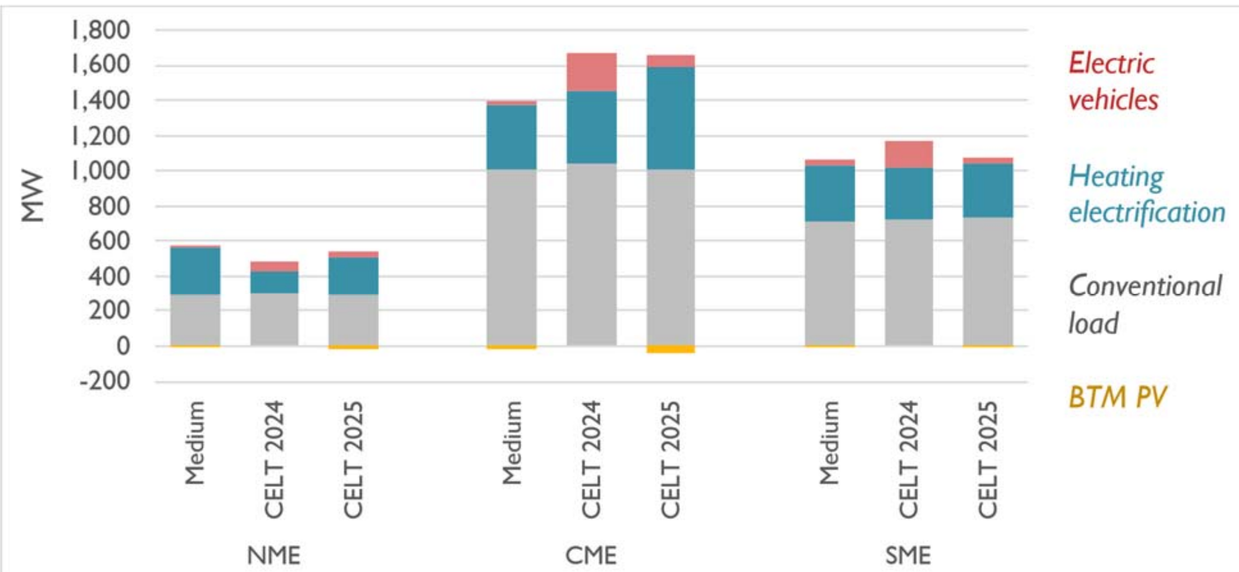
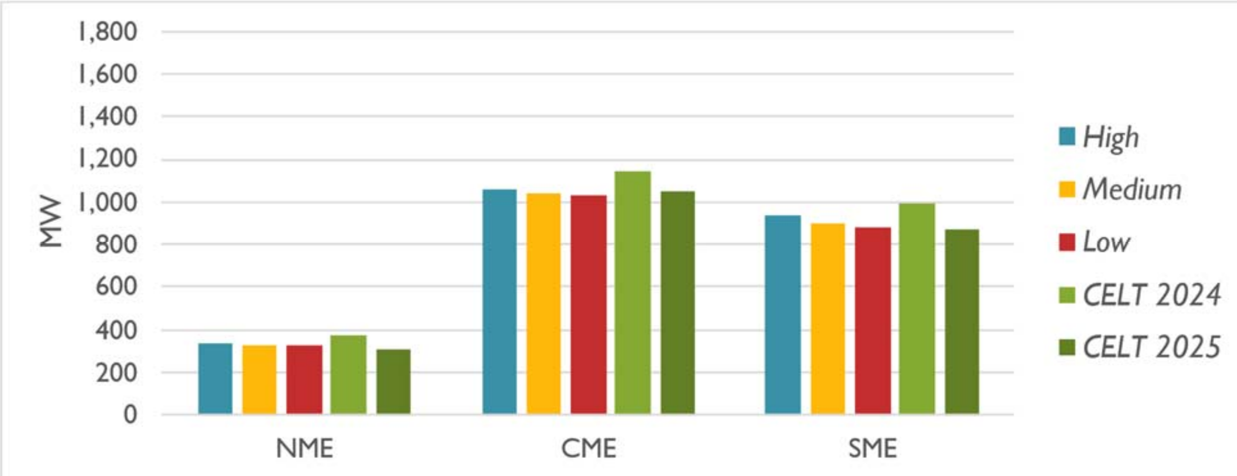


Figure 52 below compares our 2033 summer peak load forecast with ISO-NE's 2024 and 2025 CELT summer peak load forecast by region. The 2025 CELT summer peak load is lower than the 2024 CELT across all regions, primarily due to lower estimates of EV adoption (see section 3.2). Overall, there is less variation between our scenarios and the CELT forecasts for summer peak loads than for winter peaks. The 2024 CELT summer peak forecasts exceed all our scenario in all regions, ranging from 10 to 15 percent higher in NME, 8 to 12 percent higher in CME, and 6 to 13 percent higher in SME. By comparison, our forecasts slightly exceed CELT 2025 in all scenarios in NME and SME, and they are close to CELT 2025 in the Medium scenario in CME. Our estimates are higher primarily due to higher forecasts of summer EV peak load than ISO-NE. For more discussion of these differences in transportation electrification demand, see section 3.2. We note that ISO-NE also includes a small amount of heat pump load in the summer months (approximately 2-6 MW), which we did not estimate or include in our estimates.

Figure 52. Regional summer peak load by scenario in 2033, with comparison to ISO-NE CELT 2024 and 2025



Overall, the 2025 CELT projects lower summer and winter peak loads than the 2024 CELT except for winter peak loads in NME. In summer, our estimates are generally very close to, or slightly higher than, the 2025 CELT and lower than the 2024 CELT across regions. In winter—when peak loads are expected to be substantially higher than summer peaks by 2033—we observe distinct patterns across the three subareas:

- **SME**: Our Medium scenario estimate and the 2025 CELT are very close and substantially lower than the 2024 CELT.
- **NME**: Our Medium scenario estimate and the 2025 CELT are close, with our estimate slightly higher; both are noticeably higher than the 2024 CELT.
- **CME**: The 2024 and 2025 CELT forecasts are very close to each other and are substantially higher than our estimate, but for different reasons. The CELT 2024 projects considerably higher EV load, which are likely overstated due to overestimated EV stock forecasts, while the 2025 CELT projects considerably higher heat pump loads, in part because it relies on outdated assumptions about heat pump efficiencies.

These findings indicate that utilities relying on different versions of the CELT may face materially different regional peak load projections. For example, Central Maine Power (CMP), which serves loads in SME and bases its own load forecasts on the 2024 CELT, is likely to overestimate regional peak loads, potentially leading to overinvestment in grid infrastructure to serve future demand.[93] CMP's 10-year

[93] Central Maine Power. 2025. "Integrated Grid Plan Milestone 1 Stakeholder Meeting: Inputs to the Planning Models." January 27. Available at: https://www.cmpco.com/documents/40117/162881638/IGP+Milestone+1+meeting+1-27-25+%5Bdraft+for+review+prior+to+Jan+27+meeting%5D.pdf/5b80f0d7-2210-0396-3cfc-5d9d327c3a47; Versant Power. 2024. "Integrated Grid Planning: Forecasting & Scenario Development." November 14. Available at: https://www.versantpower.com/docs/default-source/environmental/111424-integrated-grid-planning-forecasting-approach-compressed.pdf?sfvrsn=cb51c6b_1.

Greater Portland area study covering 2024–2033 provides one example of this approach.[94] By contrast, utilities such as Versant, which operates in NME and also relies on the 2024 CELT, may underestimate future peak loads in that region.[95] Finally, CMP's load forecast—which also serves loads in CME—may overestimate peak loads in this region because the 2024 CELT has not incorporated results from the most recent heat pump evaluation study, which found higher heat pump efficiencies than those assumed in the 2025 CELT. Another key takeaway from this comparison is that the CELT estimates vary by region, and the magnitude and direction of differences between our estimates and CELT also vary by region. We found notable differences between our estimates and ISO-NE's 2024 CELT estimates for winter heat pump peak projections in the NME and CME subareas, in part because the 2024 CELT did not capture regional variations in weather. This finding underscores the importance of regional granularity in peak load forecasting, particularly as heating electrification increases system sensitivity to cold weather conditions.

More broadly, this comparison highlights the sensitivity of peak load forecasts to modeling methodologies and underlying data assumptions, including electrification adoption trajectories, technology efficiencies, weather representation, and assumed hourly load profiles.

The implications of these forecast differences for utility planning, grid investment, and regulatory oversight are discussed in the following section.

4.4. Planning Implications and Key Takeaways

The results of this regional peak load analysis have important implications for utility planning and regulatory oversight in Maine. Most notably, the electric system is transitioning rapidly toward a winter-peaking profile driven primarily by heating electrification. As a result, future transmission and distribution planning efforts should prioritize winter peak conditions rather than traditional summer peaks. Planning approaches that rely on statewide averages or insufficient regional granularity risk mischaracterizing both the magnitude and geographic distribution of future peak demand. In particular, colder regions such as NME face substantially higher winter peak growth than suggested by earlier forecasts, while reliance on conservative or outdated forecasts may overstate peak needs in other regions.

The comparison with ISO-NE's 2024 and 2025 CELT forecasts further demonstrates the sensitivity of peak load projections to assumptions related to electrification adoption, technology performance, weather representation, and hourly load profiles. Utilities that continue to rely on outdated CELT forecasts risk over- or under-estimating future peak loads, with corresponding implications for capital

[94] Central Main Power. 2025. *Petition of Central Maine Power Company for a Certificate of Public Convenience and Necessity: Request for Certificate of Public Convenience and Necessity for the Construction of the Greater Portland Transmission Upgrades* (Docket No. 2025-00276).

[95] Versant Power. 2025. "Versant Power Integrated Grid Planning (IGP) Milestone 2.0 Stakeholder Meeting." July 10. Available at: https://www.versantpower.com/docs/default-source/accounts---services/integrated-grid-planning-meeting-milestone-2.pdf?sfvrsn=7aa3d3ab_1.

investment and ratepayer costs. As ISO-NE and utilities update their forecasts, they should rely on the most recent CELT results and incorporate updated evaluation findings, regional weather conditions, and evolving market and policy developments, including changes in EV incentives and managed charging participation. Continued validation and refinement of load forecasting methods will be necessary to ensure that grid investments remain aligned with actual system needs as electrification accelerates across Maine.

Appendix A - Alternative peak load impact analysis

The lowest temperatures identified by ISO-NE for "90/10 load" conditions are not as severe as the "90/10 temperatures", which represent the coldest temperatures expected to occur once every 10 years. This discrepancy likely stems from the ISO's reliance on current load conditions, which are less sensitive to outdoor temperatures due to limited space heating electrification. However, as space heating becomes increasingly electrified, system load will become more responsive to cold weather. Over time, the temperatures associated with 90/10 load conditions are expected to be substantially colder than the ISO-NE's current assumption. To account for this future sensitivity, we conducted an alternative peak load impact analysis using more extreme winter temperatures, which are shown in the table below, along with the minimum temperatures based on ISO-NE's 90/10 load conditions, which we used in the analysis discussed in Section 3.1. The alternative minimum temperatures are approximately 6 to 7 degrees colder than the minimum temperatures based on ISO-NE's 90/10 load conditions.

Table A-1. Alternative minimum temperatures vs. minimum temperatures based on ISO-NE's 90/10 load conditions

	Northeastern Maine (NME)	Southeastern Maine (SME)	Central Maine – (CME)
Minimum temperatures based on ISO-NE's 90/10 load conditions	-4.8	1.8	-1.5
Alternative minimum temperatures based on HVAC industry standards	-11.6	-4.0	-7.8

We developed these alternative minimum temperatures based on HVAC industry standards, incorporating the following key assumptions:

a) **Heating design temperatures at the 99th percentile**: HVAC contractors typically use design temperatures defined by (a) an HVAC installation manual called Manual J produced by the Air Conditioning Contractors of America Association, Inc. ("ACCA"),[96] (b) weather data published by the American Society of Heating, Refrigerating and Air-Conditioning Engineers ("ASHRAE"),[97] or (c) local building codes. The HVAC industry standard is to size heating systems based on the 99th percentile design temperature, representing weather conditions for which appropriately

[96] Air Conditioning Contractors of America (ACCA), *Manual J Residential Load Calculation*, Available at: https://www.acca.org/standards/technical-manuals/manual-j.

[97] ASHRAE, *Climatic Design Conditions 2009/2013/2017/2021*, Available at: https://ashrae-meteo.info/v2.0/.

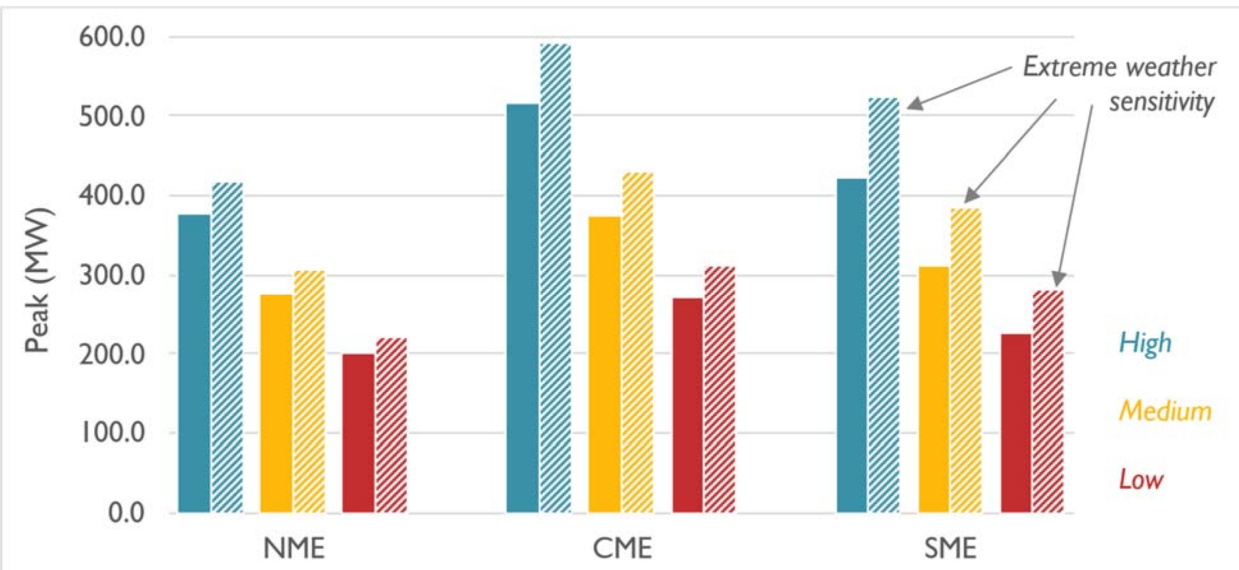
designed equipment will fully provide space heating loads for 99 percent of the hours in a typical year.[98]

b) **A heat pump oversizing factor of 15 percent**: HVAC contractors may oversize heating systems beyond the size corresponding to the 99th percentile design temperatures when the exact heating equipment size to match calculated loads is not available or if they want an additional safety margin. The 15 percent oversizing factor is drawn from a 2020 study by the Northeast Energy Efficiency Partnership (NEEP).[99]

Heating loads are estimated based on degrees Fahrenheit below 65°F. For example, in Southeastern Maine, the design temperature is 5°F—60 degrees below 65°F. Applying a 15% oversizing factor results in a load equivalent to 69 degrees below 65°F, corresponding to a minimum temperature of -4°F (i.e., 65°F - 69°F = -4°F).

As shown in Figure, the alternative weather results in winter peak load increases of 11 percent in NME, 15 percent in CME, and 24 percent in SME. In the Medium scenario this corresponds to increases of 30 to 74 MW.

Figure A1. 2033 winter peak by scenario and region, including alternative extreme weather sensitivity



[98] Allison A. Bailes III. 2021. "Design Temperature vs. Degree Days." Available at: https://www.greenbuildingadvisor.com/article/design-temperature-vs-degree-days.

[99] NEEP. 2020. *Guide To Sizing & Selecting Air-Source Heat Pumps in Cold Climates*. Available at: https://neep.org/sites/default/files/resources/ASHP%20Sizing%20%26%20Selecting%20-%208x11_edits.pdf.

APPENDIX B – ABBREVIATIONS

ACCA	Air Conditioning Contractors of America Association, Inc.
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers
BEV	Battery Electric Vehicles
BHE	ISO's Bangor Hydro
BTM	Behind-the-Meter
CELT	Capacity, Energy, Loads, and Transmission
CME	Central and Western Maine
CMP	Central Maine Power
COP	Coefficient of Performance
DERs	Distributed Energy Resources
EE	Energy Efficiency
EMT	Efficiency Maine Trust
EV	Electric Vehicle
GSHP	Ground-Source Heat Pump
HPWH	Heat Pump Water Heaters
HVAC	Heating, Ventilation, and Air Conditioning
IGP	Integrated Grid Planning (Versant Power)
ISO-NE	ISO New England
LDV	Light-Duty Vehicles
LBNL	Lawrence Berkeley National Laboratory
LMI	Low- and Moderate-Income
MDV/HDV	Medium- and Heavy-Duty Vehicles
MOT	Maine Office of Tourism
NEEP	Northeast Energy Efficiency Partnership
NME	Northeastern Maine
NREL	National Renewable Energy Laboratory
OPA	Maine Office of the Public Advocate
PHEV	Plug-in Hybrid Electric Vehicles
PV	Solar Photovoltaics
SAE	Statistically Adjusted End-Use
SME	Southeastern Maine (including Portland)
Synapse	Synapse Energy Economics, Inc.