Appendix L

Demand Management Program Analysis and Considerations

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By Ian Burnes and Jack Riordan
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Introduction

1. What is the purpose of this testimony?

The purpose of this testimony is to describe and provide information about the Efficiency Maine Trust's (the Trust's or EMT's) Demand Management Program (DMP), which is incorporated in the Trust's Triennial Plan V. The DMP will comprise two initiatives: the Demand Response Initiative (DRI) and the Load Shifting Initiative (LSI).

2. Who is introducing this testimony?

The testimony is provided by the Trust's Ian Burnes, Director of Strategic Initiatives, and Jack Riordan, Strategic Initiatives Manager.

3. Mr. Burnes, please state your name, title, and business address.

My name is Ian Burnes, and I am employed by EMT as the Director of Strategic Initiatives. My business address is 168 Capital Street, Suite 1, Augusta, ME 04330.

4. Mr. Burnes, please summarize your education experience.

I have a Bachelor of Arts degree in Economics from Wesleyan College. I have been working at the Trust since 2009. My responsibilities include the oversight of the strategic initiatives team that implements the Trust's customer tracking database, maintains the Technical Reference Manuals, oversees the program evaluations, and manages the Trust's resource in the Independent System Operator for New England (ISO-NE) Forward Capacity Market (FCM). I also have been leading the Trust's involvement with the Non-Wires Alternative Coordinator. Before coming to the Trust, I worked at the Governor's Office of Energy Independence and Security.

5. Mr. Riordan, please state your name, title, and business address.

My name is Jack Riordan, and I am employed by EMT as the Strategic Initiatives Manager. My business address is 168 Capital Street, Suite 1, Augusta, ME 04330.

6. Mr. Riordan, please summarize your education experience.

I have a Bachelor of Science degree in Conservation Biology from St. Lawrence University. I have been working at the Trust since 2016. My responsibilities include the management of the Innovation Program, management and oversight of customer data exchange between the Trust and utilities, management of various program evaluations, programmatic reporting, and support to the Trust's Non-Wires Alternative activity.

Demand Management Program Overview

7. What is the goal of the Trust's DMP?

The principal goal of the DMP is to cost-effectively reduce grid-supplied electric consumption in Maine during periods when the grid is forecasted to be at its peak.

The DMP consists of the Demand Response Initiative (DRI) and the Load Shifting Initiative (LSI). In sum, DRI will incentivize the curtailment of equipment or facility-wide electricity use during the grid's peak at commercial and industrial (C&I) facilities. LSI will incentivize flexible loads that can be controlled to run outside of peak hours, initially with battery storage systems, electric vehicle (EV) charging station controls, and thermal storage solutions. These initiatives will provide value in the form of the reduction of peak energy use as forecasted by ISO-NE, the reduction of facility peak demand charges assessed by distribution utilities, enhanced system-wide grid reliability, reduction of wholesale electricity prices, increased penetration and balancing of intermittent renewables, and environmental benefits associated with avoiding peak electricity generation.

8. Please briefly describe how DRI advances this goal.

The Trust will incentivize customers for every verified kilowatt (kW) that is curtailed when the grid is forecasted to be at its peak. The first year of DRI will be limited to C&I facilities. This program's incentive will initially be limited to the curtailing of facility equipment's electric load during summer peak events. To begin, DRI will only have a limited number of dispatches (up to eight) per summer. The Trust will rely on one or more Curtailment Service Providers (CSPs), also known as aggregators, to enroll and dispatch participating customer equipment during peak events. Customers will typically be notified the day before peak energy events will take place. CSPs will notify customers based on their communication preference (e.g., email, voicemail, and/or text message). A CSP's day-ahead notification will be based on ISO-NE's peak load forecasts.

9. Please briefly describe how LSI advances this goal.

LSI will target equipment and deployment strategies to encourage shifting load out of peak periods. The Trust will incentivize the installation of battery storage systems that can be controlled and dispatched to shift the load from the grid's peak times. The Trust will incentivize the installation of residential EV charging stations that can be controlled to shift charging schedules away from grid peak times. The EV charger measure may be expanded beyond the residential market to the extent that a market segment has a similar load profile and charging behavior to the residential measure. For instance, a fleet of commercial vehicles that are used during normal business hours and then charged overnight may be considered, but a bank of workplace chargers that are available for charging during work hours would not be considered at this point. The EV charger measure will be limited to incentivizing battery electric vehicles only. Thermal storage installations will also be configured to reduce load during peak periods. As with DRI, the Trust may rely on one or more aggregators to enroll customers and/or coordinate load-shifting schedules according to ISO-NE's peak load forecasts.

10. Have EMT demonstration projects in the Innovation Program shown capability of reducing peak demand? If yes, please describe the demonstration project's results.

EMT's Aggregated Distributed Energy Resource (DER) Load Management Pilot[1] (awarded under EMT's RFP EM-011-2018) proved the capability to control a diverse set of DERs, including air source heat pumps (ASHPs), heat pump water heaters, EV chargers, and battery storage systems. The pilot controlled a mix of 44 of these residential devices using electronic signals via a third-party internet platform. The pilot successfully tested different load-shifting strategies depending on the end-use device, including turning water heaters off for no more than 6 hours at a time, changing ASHP heating or cooling setpoints by up to 4 degrees Fahrenheit for no more than 6 hours at a time and no more than 40 hours per week, charging or discharging battery storage systems up to four times per week but not exceeding 10 times per month and never below 50% charge status, and controlling or throttling EV charging rates for up to 4 hours per day without exceeding 40 hours per week. These devices were successfully controlled during simulated peak load scenarios over the course of the year.

Once the DER fleet of 44 devices was installed and commissioned, the Trust simulated a variety of load-shaping scenarios for 12 months. Load-shaping scenarios included the reduction of consumption at the time of annual peak generation capacity in June, July, and August. Additionally, in the fall and winter months, the provider ran the simulation of different time of use (TOU) rates to reflect the differences in cost of generation at different times of day. The provider also responded to monthly peak demand times that are used to allocate shared regional transmission costs to ratepayers and ran a scenario that optimized distributed load for lowest carbon impact.

Back-up Batteries

In the pilot, batteries demonstrated the largest reduction capacity and exhibited the most flexibility of all controllable devices. The primary driver for residential battery purchases was found to be the desire to secure backup power for use during grid outages. In these situations, battery availability was also found to be largely independent of customer behavior, and batteries tended to be available when called upon in the pilot. The pilot also identified battery storage systems as the highest value, near-term opportunity for distributed load flexibility. If purchased solely to provide demand management, batteries are generally too expensive to satisfy the Trust's cost-effectiveness test where the test accounts for the full cost of the battery and its installation. However, if a customer has already decided to purchase (and pay for) a battery for emergency backup power, then the relatively minor incremental cost of adding controls and providing financial incentives to manage demand are more than offset by the economic benefits, making the measure cost-effective.

EV Chargers

EV chargers were found to be a significant load, but their availability as a demand flexibility resource was low. This is particularly true of residential EV chargers, which tend to have a relatively low duty cycle

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[1] The full report can be found on the Trust's website: https://www.efficiencymaine.com/docs/Efficiency-Maine-Revision-DER-Pilot-Final-Report.pdf.

and even lower peak coincidence. However, the penetration of EV chargers is expected to grow significantly in the coming years, and controlling these resources to manage peak load will grow in importance with time. This pilot also indicated strong customer acceptance and low opt-out rates, with most customers never opting out of an event. In addition, the demonstration project's customers indicated a strong willingness to participate in a similar program in the future.

Heat Pump Water Heaters and Heat Pumps

Heat pump water heaters and heat pumps proved less viable as load management devices in the pilot because they are so efficient to begin with; the energy savings associated with load shifting is relatively insignificant on a per-unit basis. As a result, the measure's cost-effectiveness is very sensitive to the cost of customer acquisition and maintenance. If, for example, a customer loses internet connectivity and requires a technician to spend time on the phone restoring service, that extra cost might render the measure not cost-effective.

11. Are there other ongoing EMT demonstration projects in the Innovation Program that might provide additional insights for the DMP?

EMT's Commercial Battery Storage Load Management Pilot (also awarded under EMT's RFP EM-011-2018) is designed to deploy batteries at three different small and medium-sized businesses in Maine. The pilot is designed to simulate potential revenue streams from ancillary grid services, measuring potential benefits to the customer and electric ratepayers. This project is currently in its test year, during which time the provider will collect and analyze battery dispatch activity data.

Additionally, EMT's Level 2 Smart Charging Pilot (awarded under EMT's RFP EM-009-2020) is designed to recruit both EV Accelerator Program participants who do not have Level 2 chargers and new EV owners through area dealerships. The participants in the pilot are randomly assigned to either a Smart Charge Group or Simulated TOU Group. The Smart Charge Group receives incentives that cover data communications as well as a discount on the equipment once the installation is verified and communicating with the central database. The TOU Group receives incentives covering data communications plus quarterly incentives based on maintaining 90% of their charging off peak. The Trust will analyze the charging data from a central interface and manage the incentive payments and program reporting. The goal of the Level 2 Smart Charging Pilot is to encourage off-peak EV charging using two approaches: (1) an "upstream," equipment-based solution in which participants receive a Level 2 charger with a pre-set off-peak charging schedule, and (2) a rebate-based solution in which participants receive financial rewards for charging off peak. At the time of writing, the Trust has enrolled 100 Maine EV owners as pilot participants and is currently in the phase of installing equipment and collecting data.

The Cold Storage Facility Load Management Pilot (awarded under RFP EM-012-2019) is designed to deploy thermal energy storage systems and configure them to shift load to off-peak times in facilities with large commercial freezer spaces utilizing racked, phase change material (PCM) systems with controls. The PCM increases thermal storage capacity of the freezer and allows for modulation of freezer refrigeration load to shift away from peak periods. Currently, a total of three sites have been enrolled under this initiative, with one site installed and currently in the measurement and verification stages of the project.

12. Have other jurisdictions in the Northeast successfully implemented similar programs to DRI and if so, what is the basic design of such programs?

Yes, the Connected Solutions Active Demand Response (ADR) Program incentivizes commercial and industrial customers served by National Grid, Eversource, and Unitil in Massachusetts, New Hampshire, Connecticut, and Rhode Island. This program incentivizes customers to reduce their electricity demand when the grid is forecasted to be at its peak. Customers are compensated on a pay-for-performance basis for every average kW they reduce during an assessment period. Customers typically enroll through an approved CSP that provides services to make it easier for customers to maximize their performance and incentive. The Connected Solutions ADR Program offers numerous dispatch options depending on the state but typically includes:

- Summer-targeted dispatch that aims to reduce grid load at the one peak hour of the year;
- Daily dispatch that aims to reduce the one peak hour of the year as well as daily peaks in July and August; and
- Winter-targeted dispatch that aims to reduce load up to five peak days in the winter.

The Connected Solutions ADR Program also offers different technologies for commercial and industrial facilities including equipment-agnostic curtailment, battery storage, and thermal storage. Incentive rates vary depending on the technology and dispatch scenario, with equipment-agnostic curtailment targeted at summer-peak dispatch typically carrying the lowest incentive level and battery storage daily dispatch typically carrying the highest incentive level.

DRI Program Considerations

13. Please describe how and when DRI resources will be dispatched under the Triennial Plan.

The CSP will notify the customer of demand response events the day ahead of the event. CSP notifications will be based on the ISO-NE system peak load forecast, and the CSP will be responsible for notifying the customers when an event has been scheduled. Typically, CSPs offer a variety of notification choices, including email, voicemail, phone call, text message, or machine-to-machine communication. Customers and CSPs are responsible for implementing the necessary communications so that customers are notified of the events. Typically, when an event is called, customer equipment will be dispatched by the CSP using remote electronic signals from an internet-based controls platform. The customer-owned devices are integrated with this platform and will respond accordingly to the signal. Dispatch event call periods will typically last for a limited number of hours and occur on weekdays from approximately 2 p.m. to 7 p.m. during the months of June through September. Initially, there will be no option to participate in weekend events. If weekend events are called in the future, they will be optional. A program holiday calendar will be provided to all participants, and no events will be called on these days. A typical season will include two to eight dispatch events.

14. What are the eligibility criteria that EMT will utilize to screen DRI participants?

To be eligible for EMT's DRI, customers must have an account with a Maine electric utility at the site of the proposed project and pay an assessment for the state's Electric Efficiency Procurement. The customer must have an electrical demand greater than the total demand reduction from the measure proposed at each site and have an interval meter for performance validation. Customers must enroll in the program prior to the relevant enrollment deadline, typically May 31 for summer dispatch programs. The following properties or facilities will be excluded from eligibility under DRI:

- Properties/facilities for which DERs or generation resources (photovoltaic, energy storage systems, or combined heat and power) are sited behind the same meter[2];
- Properties/facilities that do not have working interval meters (customers, at their expense, may choose to install an interval meter if they currently do not have one);
- Properties/facilities that are not served by a Maine electric utility; and
- Properties/facilities customers (or properties/facilities) that do not pay into the State's electric energy efficiency fund.

Reductions under DRI must offset coincident, on-site consumption of grid-supplied energy. The reductions must be measurable, and the customer's equipment must be grid-connected. Projects must also be reasonably expected to provide the load reductions forecasted. Project applications will be reviewed by the Trust, in concert with the CSPs, to ensure that load reduction forecasts are reasonable.

15. How does the Trust propose to market and enroll customers for DRI?

The Trust will establish a dedicated DRI web page and provide program requirements and application materials upon request. In addition, the Trust will leverage its existing customer and vendor relationships to make potential participants aware of program offerings. The Trust also will partner with qualified CSPs to complete customer recruitment and enrollment. CSPs will work directly with customers and provide the demand management expertise and services to assist customers with the identification of demand management solutions that align with the Trust's incentive program requirements and that are technically feasible. The Trust and its third-party evaluators and technical assistance providers will support CSP program staff to address any additional information needs of the program participants.

16. What is the CSP role in DRI?

CSPs will be crucial in supporting the customer and maximizing the customer's curtailment performance and incentive. Enrolling through an approved CSP is a requirement of the program at this time, but customers may use any Trust-approved CSP they choose. The Trust will curate a list of approved CSPs for reference by potential program participants. The Trust will also look to build upon relationships with customers who have participated in past Trust programs and look to make appropriate connections between CSPs and potential program customers. Recognizing that customers may decide to opt out of the program at any time, the Trust will work with CSPs to enroll customers on an annual basis and aim to retain participants in subsequent years.

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[2] The Trust may allow emergency generation with proper environmental permits so long as those generators could not run parallel with the grid.

LSI Program Considerations

17. Please describe how and when LSI resources will be dispatched.

LSI measures, including thermal storage–PCM, EV chargers, and residential and commercial battery storage systems, will not be dependent upon CSP call events.

Thermal storage –PCM installations will be configured to dispatch daily during scheduled dispatch windows at a frequency of 60+ days per demand reduction season.

For the EV chargers measure, chargers will not be directly dispatched by a control signal, but participants will be incentivized to delay EV charging to off-peak hours through EV charger controls configuration or manual charging schedules. The Trust will pay EV Charger participants an initial incentive for enrollment in addition to a recurring annual incentive for continuing to take part in the program. If the utilities develop TOU rates that effectively incentivize off-peak charging, the Trust may not need to continue the recurring performance incentives.

Finally, both residential and commercial battery storage system controls will be programmed to dispatch daily during scheduled peak demand dispatch windows. Commercial battery storage systems will be programmed to dispatch 60+ times per season, while residential battery storage systems will be programmed to dispatch between 30 and 60 times per season.

18. What are the eligibility criteria that EMT will utilize to screen LSI participants?

To be eligible for LSI incentives, customers must have an account with a Maine electric utility at the site of the proposed project and pay into the state's electric energy efficiency fund.

Eligible EV charger products required for participation will be identified and shared by the Trust with vendors and participants and incentivized to delay their EV charging to off-peak times. EV charging will be screened for cost-effectiveness at the program aggregate level and annual per-participant recurring incentives will only be paid pending continued participant connectivity.

Thermal storage–PCM installations will be screened for cost-effectiveness as in the Trust's Commercial and Industrial Custom Program process. Due to the custom nature of these installations, project costs and estimated demand reductions will be individually validated and screened. Cost-effective installations will be incentivized for installation and configured for daily dispatch during the established peak demand dispatch window. Thermal Storage–PCM incentives will be a one-time, up-front payment based on the cost-effectiveness screening.

Residential and commercial battery storage system installations must also be deemed compatible based on the Trust's system requirements and include the capability to allow for daily dispatch controls programming. The Trust will require verification of connectivity and curtailment performance prior to paying performance-based incentives for battery storage system installations. Also, battery storage system incentives will be based on verified load reduction after the dispatch window is over.

19. How does the Trust propose to market and enroll customers for LSI?

The Trust will establish a program web page that lists program requirements, eligible product lists, required equipment configurations for system dispatch, information on peak demand dispatch windows, and application materials. The Trust will implement online advertising strategies where applicable. The Trust will also work with vendors, equipment suppliers, and installers to promote LSI and provide the information necessary for potential customers to participate. In addition, the Trust will leverage their existing customer and vendor relationships to make potential participants aware of program offerings. The Trust's program delivery staff will also support potential customers and project developers in assessing potential customer participation. The Trust's program delivery team staff will review LSI program applications and enroll eligible participants into the program using the Trust's project tracking database.

20. How is a DRI participant's baseline and performance calculated?

To calculate a demand response customer's performance during a demand response event, it is first necessary to calculate a customer's typical power use to estimate what the power use would have been if no dispatch event were called. DRI will use a last 10-of-10 model for baseline calculations. This approach is comparable to the baseline calculation methodology of ISO-NE's demand response program.[3] This method looks at the customer's last 10 "similar days." Similar days are days of the same type (weekday) that are not holidays on which no other demand response event from either ISO-NE or a utility was called. The Trust may take steps to alter this baseline methodology to the extent that it can increase the unpredictability of the days on which the baseline will be set. Days on which a customer has a scheduled shutdown are not considered similar days. For shutdown days to be excluded from the baseline calculations, customers or their CSP must inform the Trust of the shutdown with at least one week's notice.

Demand response events are called during extreme weather. The day of the event may be hotter than the last 10 similar days, and the customer's load may be higher that day. To account for this, the baseline is adjusted to reflect the customer's load during the demand response event day. This is called the baseline adjustment—the difference between the customer's average load during the hour starting the 2 hours before the event starts and the load during the event day. However, the customer's load may be lower during an event day than the last 10 similar days because the customer is responding to the demand response event. Therefore, the adjustment can only be positive. The baseline adjustment will never penalize the customer.

The Trust will reserve the right to account for any anomalies in the customer's interval data and adjust the baseline to accurately reflect the customer's performance. Although it is rare, sometimes the baseline adjustment causes the baseline to be adjusted to a level higher than the customer ever uses. A customer cannot curtail more load than they use. To prevent this, the event day performance must be

[3] See, e.g., ISO New England Inc., *Measurement and Verification of Demand Reduction Value from Demand Resources*, Manual M-MVDR, Revision 6, 2014, slides 21-34.

smaller than the maximum load of the customer during the last 10 similar days. Performance for an individual demand response event is calculated by subtracting the customer's average power (kW) use over the demand response event from the customer's adjusted baseline power. Negative performance is not penalized.

21. How is an LSI participant's baseline and performance calculated?

For EV chargers the baseline of a typical charger will be determined through the results of the ongoing EMT Smart Charge pilot. This pilot will be used to determine the baseline load, program impacted load, and load reduction. Thermal storage projects will receive custom measurement and verification due to the complexity of the measure. Battery energy storage projects will leverage Battery Management System data collected by the vendors to validate performance. Interval meter data analysis may also be utilized when available.

22. How will utility data be used to evaluate DRI performance?

Customer performance will be measured utilizing interval data collected by the utility meter. All participants are required to have metering capable of sending real-time interval data. In most cases, the customer already has a utility interval meter that records and transmits the information needed to complete the performance calculations. If this is the case, no other metering is required to participate in DRI. Customers who do not have an interval utility meter may also participate, but the customer or the CSP must install revenue grade metering to measure the customer electrical load in at least 15-minute intervals for the entire dispatch season. This data must be shared with the Trust. The cost for this added metering is the sole responsibility of the customer or the customer's CSP. The participant and the CSP must ensure that the Trust receives the interval meter data for performance validation. The establishment of the participant's baseline and performance validation will not be completed without interval data.

23. Will customers be penalized for poor performance?

The DMP is a voluntary program and will not penalize customers for poor or non-performance. For DRI, if a customer chooses not to participate in an event, the baseline method and performance calculation will be completed as if the customer had participated but delivered zero reduction. This will result in a lower calculated performance for that event, which will lower the customer's average performance and the incentive for the season. DRI will allow customers a certain amount of shutdown days per season. Shutdown days are typically related to facility maintenance requirements and are limited to 10 per year. The Trust will request that the customer or the customer's CSP inform the Trust of these shutdown days with at least one week's notice. Shutdown days will be excluded from the customer's baseline calculations and will generally benefit the customer's seasonal performance calculations. For LSI there are no penalties for non-performance.

24. How will the Trust calculate and distribute incentives for DRI?

The incentive award will be capped based on the magnitude of the validated demand reduction in grid-supplied energy (kW) based on meter data analysis. Final incentive amounts will be adjusted by the Trust at the end of a season as necessary to reflect the validated demand reduction. The incentive rates refer to the average curtailment amount across every event of the demand management season. If a customer chooses not to participate in an event, the baseline method and performance calculation will be completed as if the customer had participated. This would likely result in a low calculated performance for that event, which would lower the customer's average performance and lower the incentive for the season. Incentive payments for the program will be made after the season ends. The performance incentive will be sent directly to the customer's CSP at the end of the season. This allows the CSP to remove its fees from the incentive and pass the remainder through to the customer. The Trust will face minimal to no risk in terms of incentive payments, as all incentives will be based on a customer's validated performance and paid after the season is over. Additionally, for a customer to receive the performance incentive, a customer must remain in the program for the entirety of the season. A customer cannot enroll partway through a season and receive the performance incentive for fewer events than all the other program participants.

25. How will the Trust calculate and distribute incentives for LSI?

The Trust's incentive calculations will vary by LSI measure.

For thermal storage–PCM, a one-time, up-front incentive will be calculated based on a percentage of the total project cost for cost-effective installations. Thermal storage–PCM installations will be expected to be configured to discharge during peak demand windows established by the Trust but will not be paid an annual performance incentive for demand impacts. However, thermal Storage–PCM projects will be subject to customized measurement and verification to validate installation performance.

EV Charger participants will not be paid based on demand impact performance (in $/kW). Instead, EV Charger participants will be paid a one-time incentive for purchasing eligible equipment and enrolling in the program, in addition to a recurring annual incentive payment for continued participation verified based on device connectivity.

Incentives (in $/kW) for residential and commercial battery storage systems will be based on performance verification completed after the seasonal peak demand dispatch window is closed. Performance verification will be completed for all installations and be based on analysis of energy metering data for the battery storage systems.

26. How will the Trust track demand reductions for the DMP?

The Trust will use third-party technical assistance and evaluation providers to study the response rate and demand reduction resulting from customer participation in the DMP. The program will be continually assessed moving forward, and demand reductions will be tracked and calculated based on meter data analysis. The Trust will plan to report validated program demand reductions and any updates to the program's design in the Trust's annual reporting.

DMP Cost-Effectiveness Considerations

27. Please explain the Trust's approach for calculating the cost-effectiveness of the DMP.

The Trust uses the methodologies and assumptions consistent with other measures included in Triennial Plan V, with three exceptions that are needed to account for the dispatchability of demand management measures.

The first difference is that the Trust used uncleared values for benefit streams, assuming that this program would not be bid into the ISO-NE FCM in its initial years since auctions for those years have already been completed. This contrasts with the rest of the Trust's energy efficiency portfolio, which uses the cleared values and bids those measures into the FCM.

A second difference is that for the estimation of Wholesale Capacity DRIPE, the Trust's analysis reflects this as the net present value (NPV) of the Avoided Energy Supply Cost of New England 2021 (AESC 2021)[4] uncleared schedule, including the first five years that do not accrue any benefits at the beginning of the study period. The NPV of this avoided cost over the study period is considered the single-year value stream for the analysis. This methodology reflects the following AESC guidance:

> …benefits from uncleared resources must be summed over the study period, rather than the measure life. This is because benefits do not accrue until after the measure has been in effect for a few years, and because benefits continue to accrue for several years after the measure ceases to be active, as the load reduction moves through the 15 years of data used in the ISO load-forecast regression.[5]

Lastly, because the Trust is not going to bid this program's capacity savings into the capacity market, the savings are "uncleared" and do not produce direct avoided costs within the capacity market.[6] However, these measures still provide system benefits by impacting ISO-NE's forecast of load, which is one of the inputs used to develop prices in the capacity market. The Trust applies a scaling factor that can be thought of as a measure of the efficiency of load reduction in reducing ISO-NE's forecast of load.[7] The Trust used the AESC Appendix K workbook to estimate the appropriate scaling factor based on the dispatch characteristics of the measure. This factor is then multiplied by the uncleared capacity or uncleared capacity DRIPE avoided cost (calculated using the AESC 2021 User Interface) and the measure's capacity savings and seasonal coincidence factor to provide the final benefit value.[8]

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[4] Synapse Energy Economics, Inc., *Avoided Energy Supply Components of New England: 2021 Report,* Prepared for AESC 2021 Study Group, March 15, 2021 (see Appendix G-2).

[5] AESC 2021, p. 377.

[6] AESC 2021, p. 377.

[7] AESC 2021, p. 384-385.

[8] AESC 2021, p. 385-386.

28. Please comment on the cost-effectiveness of the DMP.

Based on estimates using EMT's approved avoided costs and an incentive rate comparable to what has been used in similar programs in other jurisdictions, the estimated benefit-cost ratios for each measure are presented below. The measures are organized in two tables, the first comprising pay-for-performance incentive measures (C&I curtailment and battery storage system dispatch) and the second comprising device-level incentive measures (thermal storage–PCM and EV charger load shifting).

Table 1: Estimated Benefit-Cost Ratios for Measures with Pay-for-Performance Incentives

Type	Measure	2023 Benefit-Cost Ratio	2024 Benefit-Cost Ratio	2025 Benefit-Cost Ratio
Demand Response	Curtailment	9.14	9.36	9.59
Load Shift	Residential Battery Storage	1.63	1.66	1.70
Load Shift	Commercial Battery Storage	2.13	2.18	2.22

Table 2: Estimated Benefit-Cost Ratios for Measures with Device-level Incentives

Type	Measure	NPV of Benefits	NPV of Costs	Benefit-Cost Ratio
Load Shift	EV chargers	$1,747,647	$1,273,403	1.37
Load Shift	Thermal Storage–PCM	$385,456	$208,011	1.85

Benefit-cost ratios for curtailment and for residential and commercial battery storage system initiatives are presented for each year of Triennial Plan V in Table 1, as these measures will pay participants annually based on their validated kW performance at the end of each dispatch season. In Table 2, benefit-cost ratios for EV chargers and Thermal Storage–PCM measures are presented and calculated based on incentives being paid on a per device basis upfront, and an annual connectivity incentive being paid for continued EV Charging participation each year thereafter. For these two measures, benefit-cost ratios are calculated based on the NPV of the costs and benefits over the lifetime of each measure rather than on an annual performance basis. The numbers presented in Table 2 represent the total NPV of benefits and costs for the Triennial Plan V timeframe.

The curtailment measure is within the range of cost-effectiveness as reported by other demand response program administrators in the Northeast. Though not all program administrators use the same avoided costs, as a comparison, utilities administering the Connected Solutions ADR Program in Massachusetts and New Hampshire reported benefit-cost ratios filed in state-specific energy efficiency plans ranging from 2.95 to 9.8. The Massachusetts utilities each use unique values for local distribution benefits, and the New Hampshire utilities apply a uniform, statewide local distribution benefit.

29. What is the Trust's proposed budget for the DMP?

Please refer to Appendix A, Budget and Performance Metrics, and Appendix B-1, Program Roll-Up.

30. How are the incentives designed for the DMP and its respective initiatives?

The incentive rates for all measures mirror the rates used by the Connected Solutions ADR Program across neighboring states. The Trust reserves the right to modify these incentive rates as needed to achieve participation goals. Selecting incentive rates similar to those used in nearby states will provide continuity for the participants and CSPs, encouraging enrollment. Furthermore, the demand reductions accrue into the same market (ISO-NE) and therefore provide similar values. A benefit-cost test was run on the incentive rates to ensure that the program is cost-effective to Maine ratepayers. Initial incentive rates for all measures can be referenced in Table 3 and Table 4.

Table 3: Measure Incentive Rates for Pay-for-Performance Incentives

Type	Measure	Incentive
Demand Response	Curtailment	$35/kW
Load Shift	Residential Battery Storage System	$225/kW
Load Shift	Commercial Battery Storage System	$200/kW

Table 4: Measure Incentive Rates for Device-level Incentives

Type	Measure	Incentive
Load Shift	EV Chargers	$75 upfront and a fixed $50 per connected year thereafter
Load Shift	Thermal Storage–PCM	75% of up-front project costs

31. What is the Trust's proposed demand reduction target for the DMP?

The following tables summarize the targets for Triennial Plan V demand reductions through the DMP. Target reduction amounts (MW) are expressed by measure (enrolled, as reported, and as evaluated) for each year of the Plan. There are separate tables for measures that are incentivized using a pay-for-performance approach and measures that are incentivized at the device level.

Table 5: Estimated Pay-for-Performance Measure Demand Reduction Targets for 2023

Type	Measure	Demand Reduction Budget Enrollment Target (MW)	Demand Reduction Reported Target (MW)	Demand Reduction Evaluated Target (MW)
Demand Response	Curtailment	11.2	8.0	6.5
Load Shift	Residential Battery Storage System	0.33	0.13	0.11
Load Shift	Commercial Battery Storage System	0.25	0.20	0.18
Total		**11.75**	**8.37**	**6.82**

Table 6: Estimated Device-level Incentive Measure Demand Reduction Targets for 2023

Type	Measure	Demand Reduction Budget Enrollment Target (MW)	Demand Reduction Reported Target (MW)	Demand Reduction Evaluated Target (MW)
Load Shift	EV Chargers	1.5	0.13	TBD
Load Shift	Thermal Storage–PCM	0.05	0.03	0.02
Total		**1.6**	**0.16**	**TBD**

Table 7: Estimated Pay-for-Performance Measure Demand Reduction Targets for 2024

Type	Measure	Demand Reduction Budget Enrollment Target (MW)	Demand Reduction Reported Target (MW)	Demand Reduction Evaluated Target (MW)
Demand Response	Curtailment	14.0	10.1	8.2
Load Shift	Residential Battery Storage System	0.49	0.19	0.16
Load Shift	Commercial Battery Storage System	0.38	0.30	0.28
Total		**14.83**	**10.54**	**8.59**

Table 8: Estimated Device-level Incentive Measure Demand Reduction Targets for 2024

Type	Measure	Demand Reduction Budget Enrollment Target (MW)	Demand Reduction Reported Target (MW)	Demand Reduction Evaluated Target (MW)
Load Shift	EV Chargers	4.17	0.35	TBD
Load Shift	Thermal Storage–PCM	0.023	0.014	0.011
Total		**4.191**	**0.368**	**TBD**

Table 9: Estimated Pay-for Performance Measure Demand Reduction Targets for 2025

Type	Measure	Demand Reduction Budget Enrollment Target (MW)	Demand Reduction Reported Target (MW)	Demand Reduction Evaluated Target (MW)
Demand Response	Curtailment	16.8	12.1	9.8
Load Shift	Residential Battery Storage System	0.65	0.25	0.21
Load Shift	Commercial Battery Storage System	0.50	0.40	0.37
Total		**17.91**	**12.72**	**10.37**

Table 10: Estimated Device-level Incentive Measure Demand Reduction Targets for 2025

Type	Measure	Demand Reduction Budget Enrollment Target (MW)	Demand Reduction Reported Target (MW)	Demand Reduction Evaluated Target (MW)
Load Shift	EV Chargers	8.4	0.714	TBD
Load Shift	Thermal Storage–PCM	0.023	0.014	0.011
Total		**8.4**	**0.73**	**TBD**

For a discussion on how these targets were estimated, please refer to question 32, below.

32. What is this demand reduction goal based on?

To inform estimates for the DRI Load Curtailment targets, the Trust grounded its forecast in the 2017, 2018, and 2019 evaluations completed for the C&I Connected Solutions demand response programs in Massachusetts. The numbers are benchmarked against accounts and MW enrollments for the programs, evaluated curtailment rates, and evaluated reported-to-curtailment ratios. To inform estimates of the participants required to reach the curtailment targets, the existing C&I account populations in Massachusetts were benchmarked against C&I accounts in Central Maine Power (CMP) and Versant territory only. Then, based on the load reduction targets, expected program growth rates, and average load reduction per customer, the Trust estimated the program's targets. The Trust estimated a demand reduction enrollment target, reduction target, and evaluated target based on Connected Solutions' program evaluation data. The difference between these numbers is based on the ratios between the program's initial targets, reported targets after enrollments, and the evaluated reductions. Incentives are estimated based on the reported targets. The incentive rate was based on discussion with CSPs and is also the rate reflected in the Connected Solutions program offerings for this measure. Based on data reported by the ISO-NE Demand Resources Working Group in March 2021, there currently exist in Maine 114 MW of Demand Response assets and 229 MW of On-Peak Demand Resources, providing a total of 343 MW of ISO-NE Demand Resources in Maine. Our current target estimates do not take into account the existing resources in this current ISO-NE resource report.

To estimate residential EV charger targets, the Trust benchmarked program targets against the corresponding ISO-NE 2021 transportation electrification forecast for Maine.[9] ISO-NE forecasts the electrification of light-duty vehicles, including cars and light-duty trucks, based on sourced historical vehicle registration data for future years. The Trust utilized data from the ISO-NE forecast and its underlying assumptions and assumed a 15% capture rate to estimate potential program participation rates. Due to the anticipated increase in penetration of EVs in the Maine market along with charging infrastructure, the Trust believes the target enrollments are reasonable. The incentive rate reflects a $75 per charger sign-up, along with a $50 annual connectivity incentive that is awarded to chargers that remain enrolled in the program. This incentive structure differs from the Trust's ongoing Smart Charging

[9] Victoria Rojo, "ISO-NE 2021 Transportation Electrification Forecast," presentation, February 19, 2021.

Pilot incentive rate and may result in differences in program enrollments and participant performance compared to what has been experienced in the pilot. The Trust also assumes that the program will be limited to battery electric vehicles only. The enrollment and curtailment targets reflect reasonable enrollment and curtailment expectations for this measure based on evaluations of similar programs[10] (including evaluations, reporting and analysis prepared for the Trust on EV charging in the state),[11] and Trust pilot program data.

To estimate targets related to the Thermal Storage–PCM measure, we assumed that the Trust would target eight additional project installations between 2023 through 2025. This assumption is based on the approximate recruitment rate reflected to date by EMT's PCM pilot program, of which there have been four projects identified over an approximate timeframe of 12 months. A thermal storage pilot project evaluation completed for Eversource provided additional context for the target estimation including typical rates of enrolled and evaluated kW reductions per project. To ensure that enrolling eight additional projects beyond the already identified projects would be feasible, the Trust estimated the approximate number of C&I accounts in Maine that will likely have the large cold storage areas needed for this measure based on the U.S. Energy Information Administration's Commercial Building Energy Consumption Survey (CBECS) which provides data that includes building type and space functionality. In total, and based on CBECS data, the Trust estimates there are roughly 195 potential sites in Maine that could offer suitable conditions for this measure, which includes large buildings with commercial-grade freezer storage spaces. Taking into account enrollment rates of the pilot program to date, the Trust estimates that if the program meets the enrollment targets for 2023 through 2025 it will have enrolled approximately 6.2% of these facilities at the end of the program's three years (this includes the four projects enrolled during the pilot phase of the measure plus an additional eight over the following three years). To estimate project costs, a ratio (in $/kW) of peak load reduction was estimated based on Trust pilot project cost and estimated peak demand impact data. An incentive of 75% of the upfront project cost was assumed for this measure. For this analysis, it is assumed that no recurring incentive is offered after the upfront incentive.

To inform the Residential Battery Storage System targets, the Trust benchmarked program targets found in Connected Solutions' 2019-2021 ADR reporting against the company's residential customer account population in Massachusetts. The Trust then extrapolated these targets based on Maine residential accounts for CMP and Versant service territories only. This factor was based on the installed capacity of solar per state based on Solar Energy Industries Association (SEIA) data and households per state based on U.S. Census data. The incentive rate is similar to the incentive rate offered for this measure in the Connected Solutions program and equates to $225/kW of peak demand reduction based on evaluated performance. The program administration and incentive budgets are based on the Trust's typical

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[10] Narraganset Electric Company (d/b/a National Grid), *Electric Transportation Initiative Evaluation Final Report,* Docket 4770, Boston, October 30, 2020.

[11] Convergence Data Analytics and Grounded Analytics, *Report on Electric Vehicle Charging for Efficiency Maine,* January 13, 2020.

administration rates. The Trust also reviewed the *2019 Residential Energy Storage Demand Response Demonstration Evaluation – Summer Season* prepared for National Grid and Unitil to further inform assumptions regarding typical per device enrollment, reported, and evaluated kW ratios.

To inform the Small Commercial Battery Storage System targets, the Trust reviewed the *2019 Consolidated Demand Demonstration Pilot Project Evaluation Report* prepared for Eversource, along with Trust pilot program project findings. The enrollment target per customer was assumed to be 25 kW of dispatchable capacity. The program's incentive rate is based on the Connected Solutions incentive rate, or $200/kW of peak demand reduction based on evaluated performance.

All measure targets and incentive budgets are estimated as annual cumulative totals, except for the Thermal Storage–PCM measure. The Thermal Storage–PCM measure's budgets and targets are newly enrolled (or additional incremental demand impact), as these measures are incentivized in the first year with no additional incentives provided for these installations thereafter. Thermal Storage–PCM will continue to provide benefits for an estimated 20 years, but no additional incentives will be paid out after the initial payment.

33. Does the Trust foresee further incentivization of demand response/load shifting projects that will enhance Maine's non-wires alternatives solutions?

Cost-effective demand response and load shifting, in concert with energy conservation, can play a critical role in providing non-wires alternatives (NWA) resources that are location specific and serve to defer or displace traditional grid investments on specific circuits by Maine's utilities. Due to the locational value of NWA solutions, increased levels of incentives may encourage needed participation on targeted circuits and still remain cost-effective. The Trust will consider offering additional incentives to those customers in locations where NWAs are being pursued. NWA solutions are screened for cost-effectiveness on an individual basis, as each project's economics can vary considerably. For this reason, the Trust will not recommend a set incentive amount for resources that contribute to an NWA solution, but will determine incentive amounts based on each specific project's economics and as they compare to other NWA resources and the traditional transmission and distribution options.