NHSAVES | EVERSOURCE | Liberty Utilities | New Hampshire Electric Co-op | Unitil

February 28, 2020

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Debra A. Howland
Executive Director
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301

Re: Docket No. DE 17-136
Public Service Company of New Hampshire d/b/a Eversource Energy And Unitil Energy Systems, Inc.: 2020 Demand Reduction Initiatives Supplemental Information

Director Howland:

Public Service Company of New Hampshire d/b/a Eversource Energy, and Unitil Energy Systems, Inc., hereby submit this Supplemental Compliance Filing for the 2020 Update under Docket DE 17-136 and pursuant to Order No. 26,323.

Updated versions of attachments can be made available as further analyzed data becomes final. Meanwhile Eversource and Unitil look forward to achieving the Demand Reduction goals established in this filing, and consequently providing greater energy efficiency savings to New Hampshire utility customers.

If you have any questions regarding this filing, please do not hesitate to contact me. Thank you for your assistance with this matter.

Thank you,

Matthew Fossum
Senior Regulatory Counsel
Eversource Energy

cc: Service List
Enclosures

2020

2020 Demand Reduction Initiatives

Supplemental Information

Jointly Submitted by

Public Service Company of New Hampshire d/b/a Eversource Energy

Unitil Energy Systems, Inc.

NHPUC Docket DE 17-136
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1.0 Active Demand Reduction Initiative Background

Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource"), Unitil Energy Systems, Inc. ("Unitil"), Liberty Utilities (Granite State Electric) Corp. d/b/a/ Liberty Utilities, and New Hampshire Electric Cooperative Inc., have been monitoring demand management demonstrations and programs taking place in other states to advance tailored methodologies for adoption in New Hampshire. The 2018-2020 Statewide Energy Efficiency Plan (approved and amended version submitted January 15, 2019) includes a section on Capacity Demand Management that describes many of the demand offerings being monitored as viable possibilities to model in state.

In 2019 Eversource and Unitil ("Utilities") proposed and implemented an active demand reduction ("DR") offering, the 2019 NH C&I Active Demand Reduction Initiative ("Initiative"), based on evaluated Commercial and Industrial ("C&I") active demand reduction efforts from across Massachusetts, Connecticut, and Rhode Island. Based on the success of these regional demonstration efforts, the Utilities proposed and offered the Initiative for NH customers. The Initiative was designed to provide incentives that reduce demand at peak times to realize customer value and system benefits mainly tied to avoided peak demand as quantified in the regional Avoided Energy Supply Cost ("AESC") study.

For 2020, the Utilities proposed to expand upon the successes of the Initiative and to offer a new residential Bring Your Own Device Demand Reduction Initiative ("BYOD DRI"). In the December 12, 2020 Settlement Agreement in Docket No. DE 17-136, the Utilities committed to submitting additional information on the results of the Initiative as well as additional information regarding 2020 Active DR Initiatives. Also, Order No. 26,323 (December 31, 2019) approving the 2020 Update to the 2018-2020 New Hampshire Statewide Energy Efficiency Plan, requires added evaluation and information on cybersecurity relative to the Utilities' proposed active demand offerings, and therefore that subject is likewise addressed in this document.

2.0 Results of 2019 NH C&I Active Demand Reduction Initiative

The Initiative was launched in April 2019. Forty Eversource customer sites and seven Unitil customer sites were enrolled by June 1st, 2019. The Initiative's reduction goal for Eversource was 5,000 kW over the summer and for Unitil was 1,800 kW. Over-enrollment of nominated capacity—the amount that customers commit to reducing, as opposed to actual performance reduction—is a consistent occurrence for an active demand offering and is accounted for to most effectively reconcile the individual variable adoption practices of each customer. The Utilities offered targeted dispatch load curtailment for 2019 that was a technology agnostic, pay-for-performance model. Following the Initiative's rules, customers were notified at 1 p.m. the day before the DR event, giving them preparation time to adopt the DR response. As in other states, the Utilities ran these initiatives using Curtailment Service Providers ("CSPs"). Additional information regarding the design and results of the 2019 Initiative can be found in the Table 2.0 below and in Attachment B.

Table 2.0

2019 Programs						
	Benefit/ Cost Ratio	Benefit ($000)	Total Incentive ($000)	Utility Costs ($000)	Summer kW Savings	Customers Served/Qty
Eversource						
C&I DR *(Interruptible Load)*	2.58	856.3	238.2	332.1	3,933	40
Total	**2.58**	**856.3**	**238.2**	**332.1**	**3,933**	**40**
Unitil						
C&I DR (*Interruptible Load*)	4.78	258.0	45.9	53.9	1,185	6*
Total	**4.78**	**258.0**	**45.9**	**53.9**	**1,185**	**6**

** While Unitil had seven customer sites signed into the initiative, 1 site did not achieve any savings*

2.0.1 Events

Eversource called three events in the Summer of 2019. The first occurred on July 19th. This event began at 4:00 p.m. and ended at 7:00 p.m. The second event was called on July 30th, which coincided with the annual peak hour of the ISO NE system, commonly referred to as the Installed Capacity ("ICAP") day, as this is the hour that sets the capacity cost allocations for the subsequent year. The event's duration was from 3:00 p.m. to 6:00 p.m. The final event was called on August 19th and ran from 4:00 p.m. until 7:00 p.m.

A voluntary weekend event was called on Saturday July 20th due to the ISO NE load forecast being its highest of the year. A voluntary load-reduction window was offered from 4:00 p.m. to 7:00 p.m.; there was no penalty, however, for non-participation in this event due to the event occurring outside program boundaries and expected participation was lower than those of weekday DR events.

Unitil called one event on July 30th, coinciding with the ICAP day with a duration of three hours lasting from 3:00 p.m. to 6:00 p.m.

2.0.2 Lessons Learned

Through the Initiative experience in 2019 the Utilities have identified several factors that have informed the 2020 initiative design.

The first key lesson learned is around performance and the need to over-enroll customers into the Initiative. Performance is discussed in more detail in section 2.0.3 below, but what is clear from performance evaluated against enrollment is that not every customer reduces load up to nominated capacity during each event. To meet the overall MW reduction goals of the Initiative in future years, it will be necessary to enroll more MW load into the Initiative than either the customer self-stated targeted reductions or the Utilities' filed targets. The Utilities do not anticipate a significant budget impact as a result of this decision. Because the Initiative is designed as pay-for-performance, customers are only paid for actual load reduction and not nominated capacity.

Another finding of the 2019 Initiative is that there is an undeniable customer appetite for a demand response offering. The Utilities had customers totaling over 5 MW worth of additional load that wanted to participate in the Initiative but could not due to predetermined Initiative parameters. This factor weighed critically in the proposed expansion of the 2020 offering. Based on both 2019 and 2020 demand response performance, the Utilities expect to revise and propose new expanded goals in the 2021-2023 plan that reflect the level of estimated actual (not customer self-projected or nominated capacity) market desire for this offering.

Another beneficial and related finding from the Initiative is that customers that were on the wait list wanted to be notified when events were happening regardless of whether they were participating in the demonstration. This demonstrates that customers are engaged with the demand response market and want increased communication and understanding of the types of conditions that may precipitate an event, and subsequently harness more control over their energy usage and costs. The Utilities believe this is further evidence of a strong and ready market for DR initiatives.

2.0.3 Performance

The evaluation of the 2019 Initiative reviewed several different baselines, including 10-of-10 baselines with asymmetric and symmetric adjustments. These baselines use the 10 most recent eligible weekdays occurring immediately prior to the day being estimated. The baseline shape consists of average load per interval across the eligible days. Event-day baseline adjustments are made to account for weather-related and other differences of load magnitude on event days compared to the 10 baseline days. For example, because events target peak days, customer loads on event days will generally be higher than on baseline days, so baselines will generally be adjusted upward. For 2019, Eversource and Unitil calculated and paid customer incentives based on the reported load reduction values from the vendor, which are based on a 10-of-10 baseline with asymmetric adjustment. As recommended by the independent evaluator, Eversource and Unitil will use the evaluated 10-of-10 baseline with symmetric adjustment for reporting and benefit calculation. This is similar to the methodology employed by ISO NE in its baseline calculations.

The independent evaluator also calculated load reductions based on an evaluated asymmetric baseline. The differences between demand reduction based on the reported asymmetric baseline (used for payment) and the evaluated asymmetric baseline are due to several factors. These factors include missing data (e.g., where a vendor reported demand reduction, but the evaluator did not have access to complete interval data to verify the changes in load) or misaligned data (e.g., differences in meter aggregation or inconsistencies in adjustment for daylight savings time). As the independent evaluator notes in the draft evaluation, the differences between reported and validated load reductions are not indicative of underperformance.[1]

The program used an asymmetric baseline for payment to help with customer recruitment and avoid unfairly penalizing customers who, for example, initiate an early response to an event that decreases load during the adjustment period—a possibility given the day-ahead notification the program provides. However, for the purposes of claiming savings, the evaluator recommends using a 10-of-10 baseline with symmetric adjustment to account for all positive and negative adjustments to pre-event load on the event day.

Table 2.1 shows the performance of the Eversource and Unitil customers over the course of the summer 2019 season, based on the draft evaluation results.[2] Final evaluation results—including detailed explanations of different baseline methodologies and justification for the recommended use of the symmetric adjustment baseline—are expected in the Spring and will be submitted to the Commission when complete.

Table 2.1

2019 Summer Reduction Summary		**Eversource (kW)**	**Unitil (kW)**
PLANNED	Reduction target	**5,000**	**1,800**

[1]ERS, *Cross-State C&I Demand Response Program Summer 2019 Evaluation Report*, Draft, January 22, 2020.

[2]ibid.

ENROLLED	An ex ante estimate based on customer recruitments ahead of summer activity, multiplied by an estimate of expected response based on experience. Also referred to as Nominated Capacity.	**5,905**	**1,300**
REPORTED ASYMMETRIC ADJUSTMENT	An ex post gross average DR calculation reported by vendors using all customer data, used for customer settlement. The baseline used for settlement is a 10-of-10 baseline with an asymmetric (positive only) day-of adjustment.	**5,885**	**1,299**
EVALUATED ASYMMETRIC ADJUSTMENT	An ex post gross average DR calculation performed by the independent evaluator—based on validated data only—using a 10-of-10 baseline with an asymmetric (positive only) day of adjustment.	**4,393**	**1,363**
EVALUATED SYMMETRIC ADJUSTMENT	An ex post gross average DR calculation performed by the independent evaluator—based on validated data only—using a 10-of-10 baseline with a symmetric (positive & negative), day-of adjustment. This calculation is the most neutral and is used for reporting and benefit calculation, as recommended by the independent evaluator.	**3,933**	**1,185**

3.0 2020 Active Demand Reduction Initiatives

Goals and Desired Outcomes

The goals of active demand offerings for 2020 are to flatten peak loads, improve system load factors, and reduce costs for all New Hampshire customers. The kW targets outlined in this document are tied to dispatching resources during time of the ISO NE peak. Reducing load during the peak ISO NE hour will most profoundly impact New Hampshire's share of the installed capacity cost allocation.

The 2020 Active DR Initiatives are expected to achieve savings of 10.2 MW in 2020. This includes 0.9 MW from the residential offerings (0.6 MW for Eversource and 0.3 MW for Unitil). C&I offerings are expected to achieve 9.3 MW savings (6.5 MW for Eversource and 2.7 MW for

Unitil). Eversource anticipates serving 1020 residential customers and 20 C&I customers. Unitil anticipates serving 500 Residential customers and 9 C&I customers, for a total of 1,549 customers served by the Active DR Initiatives in 2020.

Incentive levels will also play an active role in enrollment during the 2020 initiative year, as the Utilities plan to further develop vendor and participant relationships. Expanding such relationships will be critical to ensure a stable future for active DR offerings by bolstering enrollment and adoption of the offerings. Successful implementation of offerings in 2020 will demonstrate and reflect an exceedingly viable market for active DR activity in New Hampshire, attracting new vendors and, in turn, even greater participation, creating a positive feedback cycle. The table below outlines the incentive levels of the Utilities' various offerings for 2020.

Table 3.1 Proposed 2020 Incentive Levels

Residential	Eversource	Unitil
Wi-fi Thermostat	$25 sign up incentive, $20 participation	$40 sign up incentive, $25 participation
Battery Storage	$225 per kW	$350 per kW

C&I	Eversource	Unitil
Interruptible Load	$35per kW	$52 per kW
Storage Targeted Dispatch	N/A	$345

2020 Baselines

In 2020 the Utilities will pay incentives for the C&I Interruptible Load program based on the asymmetric adjustment settlement baseline. For reporting and benefit calculations, the Utilities will use the best information available. As with 2019, the Utilities anticipate that this will continue to be the evaluated symmetric baseline methodology recommended by the independent evaluator. Again, this is similar to the methodology currently employed by ISO NE in its baseline calculations.

C&I Active Demand Response Initiative

The 2020 C&I Active DR Initiative, or Interruptible Load Offering ("ILO"), expands upon the Initiative. The ILO is technology agnostic and provides an incentive for verifiable shedding of load in response to communication from the Utilities. Customers can use any technology or strategy at their disposal and earn an incentive based on their curtailment performance. The ILO utilizes the Utilities' existing energy efficiency implementation teams to assess curtailment opportunities at customers' facilities in coordination with CSPs, mentioned above: vendors who identify curtailable load, submit customer enrollment applications, manage curtailment events and calculate payments. The Utilities manage direct participants and vendors, approve program applications, call events, oversee customer performance, calculate payments and manage the ILO offerings. Additional information regarding the ILO is included as Attachment B to this document.

For Eversource, the major goal augmentation between 2019 and 2020 is an expansion of the offering from 5 to 6.5 MW responding to high customer interest exceeding the capacity of the Initiative. As of the date of this filing, the CSPs have indicated very strong interest from customers for the 2020 program, sufficient to meet or even exceed Eversource's increased goal metric.

Similarly, Unitil will increase its C&I goal from 1.8 MW in 2019 to 2.7 MW in 2020. Unitil will also offer a pay-for-performance battery storage pathway to increase customer participation. And, in addition to direct contact with customers by account executives and the CSP, Unitil will increase its marketing effort to include print advertising or direct mail.

Residential Bring Your Own Device Demand Reduction Initiative

In 2020 the Utilities will introduce the residential BYOD DRI. Customers with their own wi-fi thermostats or behind-the-meter batteries will be eligible to participate. To implement the BYOD DRI, Utilities will have a signal sent to the device manufacturer or customer who will then send a signal to each enrolled energy-using device to temporarily change its normal operations to result in load reductions. For wi-fi thermostats, incentives are paid based on customer participation. For batteries, incentives are paid based on demand quantity reduced by battery deployment. Customers retain the right to opt out of any event dispatch at any time. Additional detail regarding the BYOD DRI can be found in Attachment C included in this document, and a benefit-cost breakdown of the BYOD DRI is illustrated below.

Benefit Cost Analysis

Table 3.2 Proposed Interruptible Load Offering - 2020

2020 Proposed Interruptible Load Offering						
	Benefit/ Cost Ratio	Benefit ($000)	Total Incentive ($000)	Utility Costs ($000)	Summer kW Savings	Customers Served/Qty
Eversource						
Residential DR *(Wi-Fi Control & Storage)*	1.26	161.2	109.5	128.5	600	1,020
C&I DR *(Interruptible Load)*	3.86	1,467.1	325.0	380.2	6,500	20

Total	**3.20**	**1,628.3**	**434.5**	**508.6**	**7,100**	**1,040**
Unitil						
Residential DR *(Wi-Fi Control & Storage)*	0.66	80.6	50.0	122.1	300	510
C&I DR (*Interruptible Load & Storage Targeted Dispatch*)	2.89	657.9	175.0	227.3	2,800	9
Total	**2.11**	**738.5**	**225.0**	**349.4**	**3,100**	**519**

4.0 Eversource Demand Reduction Initiative Cybersecurity Assessment, Evaluation and Certification Strategy and Capabilities Statement

As part of the approval contained in Order No. 26,323, the Commission directed production of an Active DR pilot proposal from the Utilities and a corresponding comprehensive evaluation of the cybersecurity risks raised by those pilots. The requisite measures to mitigate or nullify those risks include both firmware and software elements and a report confirming that such cybersecurity risks for manipulation of electrical usage, access to customer personal protected data, and unauthorized alteration of equipment performance or settings have been addressed. The Order also requires the Utilities to: complete an evaluation of the relevant vendors' cybersecurity practices and certify them to be sufficiently protective; outline the measures, detection methods, and mitigation strategies to be implemented to integrate protection of customer-owned equipment and systems installed behind the meter; and explain how the Active DR pilots comply with the smart metering consent law, RSA 374:62. The report and other information required by the Commission is provided below – first for Eversource and following for Unitil.

Eversource's affiliates in Massachusetts and Connecticut have designed and deployed DR programs substantially similar to the one proposed for New Hampshire. As part of that effort, Eversource's affiliate companies throughout the overall corporate structure have developed and adopted a comprehensive cybersecurity review and assessment strategy in support of the design and deployment plan for its distributed DR Initiatives—the same review is employed for New Hampshire.

For the DR programs in each state, the cybersecurity review and assessment strategy for Eversource companies entails conducting detailed cyber security risk assessments to gain a clear understanding of each supporting client's infrastructure, including that relating to: security management, personnel security, system development, application security, system security, network security, data security, access control, vulnerability management and cloud security posture. Following that assessment, a comprehensive evaluations and certifications of the entire Distributed Energy Resource Management System ("DERMS") platform proposed architecture are undertaken. This evaluation focuses primarily on the cybersecurity controls, aspects of the systems, and applications to be used in the program. The relevant controls include the types of secure communication protocols being used, user management and authentication control mechanisms, data encryption for event calls and data while in transit, secure application plug-in (API) configurations and a variety of other key cybersecurity controls that are expected to be in place to effectively protect against various potential threat vector attacks within the DERMS infrastructure. These security evaluations and certifications are performed both on the DERMS management system platform, as well as all 3rd party vendor infrastructures (ex: Aggregators and CSPs). Therefore, the relevant Eversource systems, as well as the systems of the involved 3rd party vendors have been reviewed, evaluated and assessed to determine that they are secure and that they are using industry-appropriate software and firmware.

Once the cybersecurity risk assessments and security controls evaluations have been performed on each supporting system, a comprehensive authentication security architecture design is developed that includes overlays of the solution architecture design, data flows, integration points, authentication protocols and physical controls. This entire process is repeated at each stage of the architectural design phase. Prior to deployment, each system and application undergoes a final security vulnerability assessment, as needed penetration testing, and security code review to ensure that any potential medium and high-risk security vulnerabilities have been identified and fully remediated prior to deployment of any systems or applications into the DERMS platform into production.

Eversource notes that despite its focus and dedication to the security and integrity of its systems and those of its vendors, it does not control the security of customer-sited equipment installed beyond the meter. That aspect is left to the device manufacturers and customers. Eversource, however, takes every precaution in line with the above to assure that its systems are protected, to the greatest degree possible, from any threats that might originate from this customer-sited and customer-controlled equipment.

Additionally, Eversource is in compliance with the "smart metering consent law" in RSA 374:62, to the degree that law could apply in this context. RSA 374:62 requires that a utility obtain affirmative written consent of a customer before installing a "smart meter gateway device" on the customer's premises. Initially, Eversource makes clear that its proposal does not involve the installation of a smart meter gateway device. As described on pages 31-33 of the 2020

Update to the New Hampshire Statewide Energy Efficiency Plan, the DR program targets customers who have elected to install their own wi-fi thermostats or behind-the-meter battery in the program, and any "control" occurs via signal sent from Eversource's vendor to the device manufacturer or customer, and the device manufacturer or customer will then send a signal to, or otherwise operate, each enrolled energy-using device to temporarily change its normal operations. As such, Eversource is not installing or using any device as a communications gateway or portal to the customer's premises. Moreover, upon enrolling individual wi-fi thermostats or behind-the-meter batteries, each customer will execute a document outlining the terms of the program, and giving consent to Eversource's actions under the program, making Eversource compliant with RSA 374:62.

Eversource's IT Security Architecture and Application Security group is comprised of a dedicated team of best in class IT/OT and SCADA cyber, network and firewall security professionals, with combined experience that spans more than 25 years of supporting energy related IT projects. Eversource places a deep focus on detailing cybersecurity threat-protection measures, detection methods and mitigation strategies relating to the safety and security of customer personal identifiable data and customer-owned equipment (ex: thermostats, batteries, chargers, etc.) for behind the meter devices and systems. Also, Eversource operates in accordance with relevant Smart Metering Consent and Cybersecurity on Liberties policies and regulations. Given the breadth and depth of Eversource's personnel's experience in developing and deploying similar programs in Massachusetts and Connecticut, Eversource confirms that the potential cybersecurity risks for manipulation of electrical usage, access to customer data, and unauthorized alteration of equipment performance or settings have been sufficiently addressed and protected for deployment of this program in New Hampshire.

5.0 Evaluation of Cybersecurity Risks - Unitil

Unitil has developed a comprehensive cybersecurity assessment for vendors and 3rd party suppliers of critical functions to help gauge their overall security posture. The assessment includes analysis of its proposed solution as well as the information security program; controls related to personnel management and training; software and system development; application and data security; infrastructure and network security; access control practices; and vulnerability identification and remediation.

Unitil performed a cybersecurity assessment of EnergyHub, Inc. and the Mercury DERMS platform. EnergyHub's controls and security posture were found to be satisfactory for the scope of the project. Unitil found that EnergyHub has adequate cybersecurity protections in place to mitigate the risk for manipulation of electrical usage, breach of customer PII data, and unauthorized alteration of equipment performance or settings. Among other criteria, Unitil analyzed EnergyHub's implementation of the following:

- Hardening standards and change management
- Log capture and review
- Enforcement of least privilege and separation of duties
- Configuration management
- Intrusion Detection and Prevention system (HIDS/HIPS)
- Encryption of sensitive data in transit and at rest
- Use of SFTP over SSH for data exchange

Unitil reassesses ongoing vendor relationships annually. Vendors are required to sign an annual attestation that their information security plan, employee training, onboarding and treatment of personally identified information (PII) conforms to Unitil vendor security requirements and standards. In the event that the vendor infrastructure or cybersecurity program has undergone significant changes, the entire cybersecurity assessment will be revisited. In addition, vendors must also attest annually that they will report any breach of their networks or of Unitil sensitive data immediately upon suspicion or confirmation of a breach.

In the event that Unitil is informed of a breach at a vendor company, procedures have been put in place to mitigate the risk to Unitil's networks and data.

- Immediate closure of all gateways for information exchange including VPN and SFTP
- Discussions with the vendor security team regarding details and origins of the breach, the threat vector of the attack and indicators of compromise
- Quarantine and analysis of all systems that the vendor had access to
- Elevated scrutiny of all email received from the vendor domain

Before these security measures are lifted, Unitil requires confirmation from the vendor that its systems have been cleaned, forensically analyzed and pose no further threat to Unitil.

Unitil employs a robust approach to the security of its networks, data and systems as well as to the security of all integrations points with its vendors. Unitil, however, is not responsible for the security of any devices installed at a customer location behind the meter. Customers are responsible to implement best-practice security configurations on their home networks and to disconnect their devices from the internet in the event of a breach of their network. In addition, customers and device manufacturers are responsible to keep firmware current on all connected devices. Unitil is responsible to protect its systems from being compromised by an attack originating at a customer location on customer equipment and has adequate security in place to mitigate that risk.

Additionally, Unitil is in compliance with the "smart metering consent law" in RSA 374:62, to the degree that law could apply in this context. RSA 374:62 requires that a utility obtain affirmative written consent of a customer before installing a "smart meter gateway device" on the customer's premises. As with Eversource, Unitil makes clear that its proposal does not involve the installation of a smart meter gateway device. As described on pages 31-33 of the 2020 Update to the New Hampshire Statewide Energy Efficiency Plan, the DR program targets customers who have elected to install their own wi-fi thermostats or behind-the-meter battery in the program, and any "control" occurs via signal sent from Unitil's vendor to the device manufacturer or customer, and the device manufacturer or customer will then send a signal to, or otherwise operate, each enrolled energy-using device to temporarily change its normal operations. As such, Unitil is not installing or using any device as a communications gateway or portal to the customer's premises. Moreover, even if that were to be the case, upon enrolling wi-fi thermostats or behind-the-meter batteries, each customer will execute a document outlining the terms of the program and giving consent to Unitil's actions under the program, making Unitil compliant with RSA 374:62.

6.0 Active Demand Response Benefit-Cost Model

In 2019, the Utilities contracted with Synapse Energy Economics, Inc. to develop the active demand response benefit-cost model for New Hampshire (see Attachments D and E). An active demand response model was necessary because active demand response measures are focused on achieving kilowatt reduction during peak hours. While traditional energy efficiency measures to reduce kilowatt hours also reduce kilowatts, such reductions are not time dependent because measures are designed to achieve kilowatt hour savings. Therefore, system benefits from active DR are valued differently than those from passive benefits. A large proportion of active DR benefits come from the impact of uncleared capacity (capacity not bid into the market) on ISO NE's forecast of the ICAP. Please see Attachment A, "Synapse Memorandum – New Hampshire Demand Response Benefit-Cost Model" for additional information.

Synapse
Energy Economics, Inc.

Attachment A: Synapse Memorandum
New Hampshire Demand Response Benefit-Cost Model

Memorandum

TO: EVERSOURCE AND UNITIL NEW HAMPSHIRE ELECTRIC UTILITIES

FROM: ERIN MALONE, DANIELLE GOLDBERG, AND DOUG HURLEY

DATE: FEBRUARY 26, 2020

RE: NEW HAMPSHIRE DEMAND RESPONSE BENEFIT-COST MODEL

1. Introduction

Eversource Electric (Eversource) and Unitil Electric (Unitil) in New Hampshire required assistance developing a demand response (DR) benefit-cost (BC) screening model (DR Model). Eversource and Unitil offered demand response measures on a pilot basis for the first time as part of their 2019 Update to the joint 2018–2020 Energy Efficiency Plan, and they proposed to continue that effort as part of their 2020 Update.[1] The current New Hampshire energy efficiency BC model (EE Model) is not optimized to screen the new DR measures for cost-effectiveness because that model does not accurately calculate energy and capacity benefits specific to DR activities.

Synapse Energy Economics, Inc. (Synapse) created a DR Model to assist Eversource and Unitil in this matter. We started with the EE Model used for the 2020 Update and modified it where necessary to better accommodate DR measures. In this memorandum, we explain how we modified the EE Model for DR and why we made those modifications. We assume the reader is comfortably familiar with the EE Model, Microsoft Excel, and the 2018 Avoided Energy Supply Cost (AESC) Study.[2]

2. Overview of Avoided Capacity and Energy Costs

Our most substantial changes in updating the EE Model for DR measures were to add a tab for avoided capacity costs (the "AvoidedDemand" tab) to more accurately calculate DR capacity benefits, and to add a tab for avoided energy costs (the "AvoidedEnergy" tab) to more accurately calculate DR energy benefits. As such, this memo focuses on the avoided capacity and energy cost values and formulas needed to optimally screen DR measures. We start by providing an overview of avoided capacity and energy costs before explaining the detailed calculations in the sections that follow.

[1] See, NHPUC Docket No. DE 17-136, https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-136.html.

[2] For more information on the 2018 AESC Study, see https://www.synapse-energy.com/project/aesc-2018-materials.

2.1 Avoided capacity costs

The 2018 AESC Study:

> [D]evelops capacity prices for annual commitment periods starting in June 2018 under a future with no new energy efficiency. The capacity prices (and resulting avoided capacity costs) are driven by actual and forecast clearing prices in ISO New England's Forward Capacity Market (FCM). The forecast capacity prices are based on the experience in recent auctions and expected changes in demand, supply, and market rules.[3]

Energy efficiency and DR measures participate in the FCM and influence the market and forecasts for prices and supply. Utilities that implement such measures can claim avoided capacity by either bidding capacity (called "cleared" throughout the 2018 AESC Study and this memo) into the Forward Capacity Auctions (FCA), or by reducing peak summer loads through non-bid capacity (called "uncleared" throughout the 2018 AESC Study and this memo).[4] Uncleared capacity is eventually reflected in load forecasts for subsequent FCAs after several years of lag.[5]

DR measures differ from energy efficiency in two primary ways. First, the utilities are just starting to implement DR measures over 2019 and 2020, so they have not had the opportunity to bid these resources into the FCM. Second, DR measures typically have shorter durations (both in terms of measure lives and the hours in which they operate annually) than energy efficiency measures, impacting the avoided capacity costs.

2.2 Avoided energy costs

In New England, energy prices—and therefore avoided energy costs—vary by hour and load zone, based on real-time supply and demand in ISO New England's energy markets.[6] For simplicity, energy values are typically presented by the four primary costing periods—winter peak, winter off-peak, summer peak, and summer off-peak.

DR measures are designed to save energy during specific time periods based on electric grid characteristics and an action called by a market participant or a customer (sometimes called "active" savings). Alternatively, energy efficiency measures generally save energy throughout a year once installed because they perform the same functions as the less efficient technology while using less energy. DR measures target a smaller number of specific hours of the year, and those hours have

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[3] 2018 AESC Study, page 9.

[4] In wholesale electricity market lingo, a resource that "clears" is one that has submitted an offer at a price that was less than the clearing price in the applicable process. Here, we are referring to the FCA that selects capacity. Cleared resources are granted an obligation to deliver capacity, and the rights to receive revenue based upon the applicable clearing price.

[5] The 2018 AESC Study states all avoided capacity values in terms of kW of peak load reduction. 2018 AESC Study, page 66.

[6] See https://www.iso-ne.com/.

specific avoided costs that differ from the avoided costs aggregated within one of the four energy costing periods for energy efficiency. For the utilities to accurately calculate the benefits of DR measures, they need load shapes and avoided costs that are more granular than the four primary costing periods. Ideally, the DR Model would include hourly load shapes and hourly avoided costs to calculate energy benefits. However, 8,760 rows of data on avoided costs for each DR measure would be unwieldy, would over-complicate the already dense DR Model, and could falsely imply precision.

3. Avoided Capacity Costs

Avoided capacity costs for *cleared* resources are based on activity in FCAs. Avoided capacity costs for *uncleared* resources are based on ISO New England's forecast of system peak load. We address each of these processes in the following sections.

3.1 Cleared resources

Forward Capacity Auctions

Market participants, including the New Hampshire utilities as energy efficiency program implementers, offer to provide capacity into the FCM through an FCA. Each FCA is held more than three years in advance of the beginning of the related commitment period. Qualification for the auction begins an additional 11 months earlier, extending each FCA cycle to four full years between the time market participants anticipate developing a capacity resource and when the market recognizes those resources through payments.

The FCM's advanced planning cycle was developed to align with the construction of new gas-fired power plants. However, DR resources have a much shorter business cycle. DR providers often clear new resources in an FCA, but they implement the underlying projects well in advance of the original commitment period. Although delivered before the commitment period for the FCA in which they cleared, these resources that are early to market are still considered cleared, not uncleared.

Reconfiguration auctions occur after an initial FCA for a commitment period and take place both monthly and annually. Reconfiguration auctions are primarily a vehicle for capacity resources to trade obligations amongst themselves. They have little impact on customer costs, and thus we do not assess any avoided cost from participation in reconfiguration auctions.

Payment and price impacts

When an aggregation of DR measures clears in an FCA as a DR resource, it has two effects on costs to ratepayers: a payment and a price impact.

<u>Payment</u>

Each FCA sets a clearing price, which represents the marginal cost of capacity resources. All capacity resources that clear in an FCA receive a payment from ISO New England each month during the delivery year, based upon the amount of capacity delivered and the clearing price for the auction related to that commitment period. DR resources that are offered by the New Hampshire utilities and clear in an FCA will receive this payment during the commitment period. These payments can then be used to offset the cost of the DR and energy efficiency programs implemented during the commitment period or to fund additional program activity. Either way, New Hampshire ratepayers receive a financial benefit.

If DR resources are delivered early, as discussed above, the New Hampshire utilities can trade obligations in reconfiguration auctions, which would add to the revenue received by the New Hampshire utilities.

Price impact

By clearing in an FCA, DR resources offered by the New Hampshire utilities also displace the need for some other type of capacity resource that was offered at a higher cost. The clearing price in the FCA is thus lower for all customers throughout New Hampshire and New England. A lower clearing price results in lower costs that eventually flow through to customer bills.[7] The AESC Study refers to such a price impact as Demand Reduction Induced Price Effects (DRIPE). This impact represents the capacity DRIPE for cleared resources.

DR resources that clear in an FCA—whether they are delivered on time or early—have an impact on FCA prices during every subsequent auction in which the resource clears. This is because they always displace some other, higher-cost resource. Once the resource is retired or otherwise removed from the FCA by the market participant, any cleared capacity DRIPE value should also be removed.

Any participation in reconfiguration auctions will not have a DRIPE impact. Under most circumstances, there is no cost to customers from these auctions and thus DRIPE should not be applied.

3.2 Uncleared resources

It is likely that the New Hampshire utilities will bid into the FCA a smaller amount of DR resources than they will be able to deliver for the future commitment period covered by the auction. Because the business cycle for convincing customers to implement DR is short—typically one year on average—and the FCM cycle is more than three years, some estimation of future program activity is required. Participation in the FCM also comes with some financial risks which can be mitigated by clearing a conservative amount of resources in each FCA. For these and other reasons, not every megawatt of DR will clear in the FCM. The remainder—the uncleared resources—will have a lesser impact on all customers' bills, but they will still have some impact.

Uncleared DR resources will still reduce load as market participants respond to price signals outside the FCM structure. Participants may respond to energy price opportunities in the ISO New England wholesale energy market, or they could reduce load at retail sites to avoid demand or other peak-related charges.

[7] See 2018 AESC Study, Chapter 5.

ISO New England will eventually recognize any reduction in actual peak load at customer sites, even uncleared resources. This is because ISO New England forecasts system peak load to determine the amount of capacity it needs to procure in each FCA, and the FCA determines capacity prices. ISO New England forecasts system peak load using a complicated regression analysis that considers 15 years of historical data, among other variables such as weather. Reduced peak load by uncleared resources will eventually be incorporated into ISO New England's 15-year historical data set.

However, using a 15-year forecast delays the impact of DR savings, as each new year that includes savings from uncleared resources cycles into the forecast. Said another way, the capacity is phased into the forecast year-by-year, and it similarly phases out of the forecast over the 15-year term. As explained in the AESC study:

> Program savings that are not cleared as capacity resources provide savings much more slowly. A load reduction in 2018 will first affect the ISO New England's Spring 2019 load forecast, which will be used in the February 2020 FCA 14 for [delivery in] 2023/24. Thus, there is a five-year delay between the load reduction and its first influence on the capacity charges to load.[8]

This phase in and phase out of capacity resources within ISO New England's 15-year peak load forecast results in avoided capacity costs that differ from the avoided capacity costs used for cleared resources (which is based on FCA clearing prices).

3.3 Energy efficiency model

In the EE Model, the electric utilities indicate the amount of energy efficiency bid into the FCM using a utility-specific percentage. As explained in the 2018 AESC Study, this percentage represents "a simplified bidding strategy consisting of x percent of demand reductions from measures in each year bid (cleared) into the FCA for that year and the remaining 1-x percent not bid (uncleared) into any FCA."[9] The specific percentage reflects an individual utility's bidding strategy. In the 2020 Update, Eversource estimated that 90 percent of energy efficiency measures were cleared in the FCM while Unitil estimated that 75 percent of energy efficiency measures were cleared in the FCM.

To calculate avoided capacity costs and capacity DRIPE, these percentages are used to calculate a weighted average between the cleared and uncleared values in the 2018 AESC Study. For example, Eversource assumes that 90 percent of its energy efficiency resources were cleared in the FCM, meaning the avoided capacity cost is weighted 90 percent towards cleared values and 10 percent towards uncleared values.

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[8] 2018 AESC Study, page 103.

[9] 2018 AESC Study, page 259.

On the calculations tab of the EE Model, the weighted average avoided cost value is multiplied by capacity savings (in kW) to determine capacity benefits.[10,11]

3.4 Demand response model

In terms of avoided capacity, DR measures differ from energy efficiency in two primary ways. These differences favor using alternative methods to calculate capacity benefits in the DR Model.

First, the utilities are just starting to implement DR measures over 2019 and 2020, so they have not yet had the opportunity to bid these resources into the FCM auctions. Therefore, the planned DR measures are considered uncleared resources, and would be weighted 100 percent to the uncleared value. If the utilities plan to clear DR resources in an upcoming FCA, then the DR measures would be considered cleared resources, and the utilities would adjust the percent of cleared to uncleared resources accordingly.

Second, DR measures tend to have shorter durations or measure lives than energy efficiency. DR measures may only provide savings for 1 to 5 years depending on the customer, program, and other factors, and typically only for a few hours each year. Conversely, some energy efficiency measures can provide savings for 25 or more years, with varying hourly load shapes. Please refer to the 2018 AESC Study, Appendix J for a more detailed explanation of how programs with shorter durations merit alternative approaches to estimating capacity benefits.

2018 AESC Study, Appendix J tool

For the first time in 2018, the authors of the AESC Study developed a tool to assist energy efficiency program implementers in forecasting avoided capacity costs and capacity DRIPE for uncleared, short-duration resources (see Appendix J of the 2018 AESC Study).[12] Using this tool, the user enters the year a measure is implemented and the measure life for the measure, and the tool provides the avoided capacity costs and capacity DRIPE values for that measure.

DR Model edits

Using the 2018 AESC Study's Appendix J, we calculated the avoided capacity costs and capacity DRIPE values for all three years of the New Hampshire utilities 2018–2020 energy efficiency plan, and for measure lives ranging from 1 to 25 years. These values are provided on the "AvoidedDemand" tab within the DR Model.

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[10] Line losses are also accounted for when determining capacity benefits.

[11] In the EE Model, the calculations tabs are titled "CalcsYr1," "CalcsYr2," and "CalcsYr3."

[12] Appendix J is available at https://www.synapse-energy.com/sites/default/files/AESC-2018-Appendix-J.xlsx.

We use the wholesale values from Appendix J and convert to retail values and nominal dollars within the DR Model, consistent with how capacity costs are calculated on the "AESC" tab of the DR Model (and the "Avoided Cost" tab of the EE Model).

We updated the calculations tabs to reference the new "AvoidedDemand" tab when a measure is not bid into the FCM. When a measure is bid into the FCM or the utility wants to use a weighted average avoided cost, then the model references the respective avoided costs on the "AESC" tab.[13]

Scaling factor

As explained above for uncleared resources, due to ISO New England's use of a 15-year forecast, there is a multi-year delay from when savings occur to when they are incorporated into and therefore have an impact on the summer peak forecast.[14] The impact of a load reduction on the summer peak forecast varies with the duration of the load reduction, both in terms of hours and days relative to the summer peak. Generally, a load reduction will have a greater impact on the summer peak forecast if load is reduced for more days per year or for more years within the forecast period.

To account for this delay and varying degree to which load reductions can impact the forecast, in the DR Model, we added a column to the inputs tabs called "Limited Demand Response Scaling Factor." The percentage in this column scales the total benefits from capacity and capacity DRIPE. For example, if the scaling factor for a DR measure is 10 percent, then only 10 percent of the capacity and capacity DRIPE benefits are attributed to the measure to reflect that the measure had a roughly 10 percent impact on ISO's peak demand forecast.

The scaling factor is a measure-specific input, similar to how realization rates or free-ridership rates are measure-specific inputs to the EE or DR Model. Developing measure-specific inputs is beyond the scope of this analysis. New Hampshire utilities could study this value to better understand how DR measures impact avoided capacity costs. The AESC Study reviewed DR measures in the PJM region and estimated a 10 percent scaling factor.[15]

4. Avoided Energy Costs

4.1 Scale of energy benefits

Importantly, energy benefits typically comprise a small portion of overall DR benefits, with capacity benefits driving cost-effectiveness. This is especially true for storage measures that both save energy and use energy, and often consume more energy than they save as a result of round-trip efficiency

[13] In the DR Model, we highlighted orange cells that we modified from the EE Model.

[14] 2018 AESC Study, page 105.

[15] 2018 AESC Study, page 105.

losses.[16] Utilities will likely discharge storage resources when prices are high and charge them when prices are low, resulting in net positive benefits despite increased kWh usage. The net result, however, is typically small energy benefits as a percent of total benefits (e.g., ranging from 1 to 5 percent).

4.2 Energy efficiency model

In the 2018 AESC Study, the four energy costing periods (winter peak, winter off-peak, summer peak, and summer off-peak) are calculated using hourly data that has been aggregated using load-weighted averages for each period.[17] The EE Model calculates energy benefits based on these four costing periods.

Avoided energy costs and energy DRIPE are in dollars per kWh for the four costing periods on the "AESC" tab of the EE Model. In addition, the "Demand Lookups" tab presents energy load shapes for the four costing periods, which are used to allocate annual savings to the four periods. To calculate energy benefits, the formulas within the calculations tabs multiply (a) avoided energy costs by costing period from the "AESC" tab by (b) the net lifetime savings associated with the respective costing period determined using load shapes on the "Demand Lookups" tab.[18]

4.3 Demand response model

DR measures require more granular avoided energy cost calculations than energy efficiency measures. DR measures target specific hours of the year, and those hours have specific avoided costs that differ from the avoided costs aggregated within one of the four energy costing periods.

2018 AESC Study, User Interface tool

For the first time in 2018, the authors of AESC developed a tool called the "User Interface" to provide flexibility in estimating more granular avoided costs (see 2018 AESC Study, Appendix F).[19] As explained in the 2018 AESC Study:

> This Excel-based document allows readers of AESC 2018 to examine hour-by-hour energy prices and DRIPE values for each reporting region, for 2018 through 2035. This document serves as a data aggregator; it pulls together energy and DRIPE data for the

[16] Round-trip efficiency is the amount of energy that can be retrieved from a battery compared to the amount of energy used to charge the battery. In other words, energy out divided by energy in. Round-trip efficiency is expressed as a percentage. If a battery's round-trip efficiency is 90 percent and is charged with 100 kWh, it would be able to discharge 90 kWh of electricity. Homer Energy. "Battery Roundtrip Efficiency." http://www.homerenergy.com/support/docs/3.10/battery_roundtrip_efficiency.html.

[17] The time periods in the 2018 AESC Study are defined as follows: Winter on-peak is October through May, weekdays from 7am to 11pm; winter off-peak is October through May, weekdays from 11pm to 7am, plus weekends and holidays; summer on-peak is June through September, weekdays from 7am to 11pm; and summer off-peak is June through September, weekdays from 11pm to 7am, plus weekends and holidays. 2018 AESC Study, page 66.

[18] Energy line losses are also accounted for when determining energy benefits.

[19] The User Interface is available at https://synapseenergyeconomics.app.box.com/v/UserInterfacesAESC2018

> traditional AESC costing periods and discount rates, allowing users to view—and modify—levelized avoided costs. This document also provides an extrapolation of energy prices and DRIPE values through 2050, using the assumption that all values after 2035 are calculated using the five-year cumulative average growth rate from 2031 to 2035.
>
> However, the main purpose of this document is to allow users to develop avoided costs for periods outside the traditional AESC costing periods of summer off-peak, summer on-peak, winter off-peak, and winter on-peak.[20]

The User Interface summarizes hourly avoided costs into the four traditional costing periods, as well as an annual average across all costing periods and a dynamic costing period (i.e., where users can choose the time period over which to summarize hourly avoided costs).

The User Interface provides six avoided cost scenario options, as defined below. For example, a model user may want to know the avoided costs for the top 6 percent of hours during the summer months only. To do this, the model user would select the "Peak Load (Top %)" scenario, enter 6 percent of peak load, and select the summer season. The User Interface then produces avoided energy costs for the top percentage of system load as defined by the user.

- *Default.* Produces the same avoided costs by the four traditional costing periods as used to calculate energy efficiency avoided costs (see 2018 AESC Study, Appendix B).
- *User Input.* The model user enters specific hourly load values.
- *Peak Load (Top %).* Defined as "X" percent of hours exceeding "Y" percentile of load.
- *Peak Load (Top MW).* Load threshold defined as "X" hours exceeding "Y MW."
- *Peak Price (Top %).* Defined as "X" percent of hours exceeding "Y" percentile of price.
- *Peak Price (Top $/MWh).* Price threshold defined as "X" hours exceeding "$Y/MWh."

As explained in the following sections, we relied on the "Peak Load (Top %)" scenario and the "User Input" scenario to develop the avoided energy cost strategies ("energy strategies") for DR measures.

Energy strategies

Using the 2018 AESC Study's User Interface, we developed seven load shapes or energy strategies for the DR Model, as identified and defined below. On the inputs tabs of the DR Model, the user selects one of these seven strategies for each measure depending on how the measure is expected to use energy, which determines the avoided energy costs to use when calculating a measure's energy benefits.

[20] 2018 AESC Study, Appendix F.

The load shapes explained below are used for the utilities' DR program planning. The timing of when the utilities save energy, discharge batteries, or charge batteries throughout the year will vary depending on participant response, grid dynamics, and other impacts. If the utilities and other New Hampshire stakeholders chose to do so, they could modify the load shapes in the User Interface to reflect actual dispatch profiles. To do this, within the User Interface, the New Hampshire utilities would select the User Input scenario, add the actual hourly load shape to the "UserInput" tab, and use the avoided energy costs produced on the "CostInterface" tab within the DR Model on the "AvoidedEnergy" tab.

It is not common practice to change avoided costs from planning to reporting, however, so such a change is a policy decision. When making such a policy decision, stakeholders should weigh the cost and effort required to develop hourly load shapes for each measure, with the additional accuracy gained from using those updated load shapes. As explained above, energy benefits are a minimal portion of overall DR benefits, especially for storage measures, and undertaking this effort may incur more costs than benefits. It could be more beneficial to review actual load shapes and adjust future planning practices and assumptions, similar to how other evaluation results are incorporated into program design and modeling.

Peak load strategies

We used the "Peak Load (Top %)" scenario in the User Interface for the three energy strategies explained below.

- *Top 20 All Hours.* This load shape is for measures that target savings in the top 20 hours of the year based on the highest load for the year. We assumed 0.23 percent of load represents the top 20 hours, based on 20 hours divided by the 8,760 hours in a typical year.
- *Top 20 Summer Hours*. This load shape is for measures that target savings in the top 20 hours of the summer based on the highest load for the summer season. The summer season is defined as all hours from June through September, consistent with the summer costing period definition. We assumed 0.68 percent of load represents the top 20 hours, based on 20 hours divided by the 2,928 hours in the summer.[21]
- *Top 20 Winter Hours*. This load shape is for measures that target savings in the top 20 hours of the winter based on the highest load for the winter season. The winter season is defined as all hours from October through May, consistent with the winter costing period definition. We assumed 0.34 percent of load represents the top 20 hours, based on 20 hours divided by the 5,832 hours in a typical winter.

[21] The Top 20 All Hours and Top 20 Summer Hours produce the same avoided costs because the 20 hours with the highest load all occur in the summer. Despite this, we have included both options in the DR Model to provide the utilities with flexibility in future modeling.

User-defined strategies

We applied user-defined hourly load shapes for the four energy strategies explained below, which are associated with battery storage technology.

For storage measures, the specific hours in which the storage measure charges and discharges to the electric grid and the length of time for which the technology is discharged impact avoided energy costs. We worked with the New Hampshire utilities to define the time periods identified in the energy strategies explained below. However, as explained above, changing the timing and duration of discharge and charge will minimally impact cost-effectiveness because energy benefits are typically a small component of total benefits for storage measures.

The specific energy dispatched per hour (in kW) during the modeled time period has little impact on the avoided energy costs produced by the User Interface. The kW is only used to determine a load shape, and not actual savings or usage. For this reason, we used a load shape for an archetypal measure, and the specific kW indicated below are arbitrary in terms of developing avoided energy costs. We calculated the load shape as the ratio of (a) the kW discharged in the hour to (b) the maximum kW the technology could discharge in an hour.

- *Summer Daily Discharge*. This load shape is for measures that discharge or otherwise save grid-generated energy every non-holiday weekday in the summer season. We used a load profile as follows: the measure saves energy from June through September from 4:00 PM to 7:00 PM on non-holiday weekdays, saving 4.05 kW per hour for three hours.

- *Summer Daily Charge*. This load shape is for measures that charge or otherwise consume energy every non-holiday weekday in the summer season. We used a load profile as follows: the measure uses energy from June through September from 2:00 AM to 5:00 AM on non-holiday weekdays, consuming 5 kW per hour for three hours.[22]

- *Summer Targeted Charge*. This load shape is intended to complement the Top 20 All Hours or Top 20 Summer Hours load shape, for measures that need to be charged after discharging.[23] We used a load profile as follows: the measure consumes energy in July and August from 2:00 AM to 5:00 AM on days when the top 20 summer hours occur, consuming 5 kW per hour for three hours.

- *Winter Targeted Charge*. This load shape is intended to compliment the Top 20 Winter Hours load shape for measures that need to be charged after discharging. We used a load profile as

[22] We assume round-trip efficiency is 10 percent, and account for it in the charging profile by assuming a higher kW than in the discharging profile.

[23] Not all measures will require a corresponding energy load profile, such as thermostat set-back measures which are not required to recharge after an event is called.

follows: the measure consumes energy in December and January from 2:00 AM to 5:00 AM on days when the top 20 winter hours occur, consuming 5 kW per hour for three hours.

DR Model edits

On the new "Avoided Energy" tab of the DR Model, we provide the wholesale avoided energy costs and energy DRIPE values from the User Interface. We used the annual average or dynamic costing period values depending on the energy strategy as explained above, instead of the four costing periods. Consistent with other avoided costs, we then estimated the retail avoided costs, calculated annual avoided costs in nominal dollars, and then calculated cumulative avoided costs. We updated the calculations tabs to reference the new "Avoided Energy" tab, instead of the "AESC" tab, to calculate energy benefits.[24]

5. Inputs Tabs

Consistent with the EE Model, the rows on the inputs tabs of the DR Model represent DR measures the utilities plan to implement.[25] The utilities must populate the rows with the DR measures they intend to offer to customers.

The columns on the inputs tabs of the DR Model are the same as the EE Model, except we added four new columns.

- *Energy Strategy*. In this column, the utilities indicate which of the seven energy strategies is applicable to the measure, which determines the avoided energy costs used on the calculations tabs for that measure (see *Energy strategies*).
- *Bid into FCM*. In this column, the utilities indicate a "yes" if the measure is bid into the FCM or a "no" if the measure is not bid into the FCM. If the utilities indicate "no," then the avoided capacity costs and capacity DRIPE values from the new "Avoided Demand" tab are used to calculate benefits. If the utilities indicate "yes," then the avoided capacity costs and capacity DRIPE values from the "AESC" tab are used to calculate benefits. If the utilities prefer to use the weighted average avoided costs (see page 5 of this memo), then they would select "mixed." The selection in this column also changes the values used for reliability benefits, which the AESC Study provides in terms of cleared, uncleared, and weighted average.
- *Total for Three Years*. Most DR programs are implemented for a single year, and participants must re-enroll annually. Therefore, kW savings cannot be summed over a three-year plan term; rather the savings in the final year of the plan term represent the cumulative savings for the term, including the number of new and repeat participants. This new column allows the utilities

[24] In the DR Model, we highlighted orange cells that we modified from the EE Model.

[25] In the DR Model, the inputs tabs are titled "ADRYr1," "ADRYr2," and "ADRYr3."

to indicate which measures can roll up over the term, if at all. However, in the output tabs ("Att 1" tabs), we did not include tables that sum the three-year total. Therefore, the "Total for Three Years" column on the inputs tabs is not incorporated into a formula, but it allows the utilities flexibility in future modeling.

- *Limited Demand Response Scaling Factor*. In this column, the utilities indicate the percent capacity benefits should be adjusted to account for the impact DR measures have on ISO's load forecast (see *4. Avoided Energy Costs*).

The utilities must determine the measure-specific values to use on the inputs tabs for all rows and columns, including the new columns. Some input values could be statewide, consistent across all utilities. Other values may be utility-specific. Such decisions are for the utilities to discuss and evaluate over time and are therefore outside the scope of this Synapse project.

6. Calculations Tabs

We made the following edits to the calculations tabs.[26]

- *Measure Life*. We rounded the measure life such that the values are whole integers. This is because the energy and energy DRIPE benefit columns use a different formula than other avoided costs when referencing the new "Avoided Energy" tab. If a partial measure life were used, the energy benefit columns would not know which avoided cost year to reference.
- *Electric Energy Benefits*. This column now references the new "Avoided Energy" tab instead of the "AESC" tab.
- *Energy DRIPE*. This column now references the new "Avoided Energy" tab instead of the "AESC" tab.
- *Summer Generation Benefits*. This column now references the new "Avoided Demand" tab in addition to the "AESC" tab.
- *Capacity DRIPE*. This column now references the new "Avoided Demand" tab in addition to the "AESC" tab.
- *Reliability*. This column now references the cleared, uncleared, or weighted average reliability values on the "AESC" tab, depending on whether a measure has been bid into the FCM.

We also added new columns, as follows.

[26] In the DR Model, the calculations tabs are titled "CalcsYr1," "CalcsYr2," and "CalcsYr3."

- *Strategy, Bid into FCM, Total for Three Years, and Limited Demand Response Scaling Factor.* These new columns repeat the information in the new columns on the inputs tabs, so that the modified avoided cost formulas reference the calculations tab directly.

- *Reliability Column Reference.* This column determines the correct column to reference on the "AESC" tab for reliability benefits, depending on whether a measure is bid into the FCM. If a measure is bid into the FCM, then the cleared reliability values are referenced on the "AESC" tab. If a measure is not bid into the FCM, then the uncleared reliability values are referenced on the "AESC" tab. If a portion of a measure's capacity are bid into the FCM, then the weighted average reliability values are referenced on the "AESC" tab.

- *Key.* This column aggregates the measure's program year, energy strategy, and measure life. This information is then used to reference the correct avoided costs for the avoided energy and energy DRIPE benefits on the new "Avoided Energy" tab.

- *Line Losses.* Energy line losses are specific to the type of DR measure. For example, a DR measure that reduces peak load in the summer should use the summer peak line loss, rather than an average line loss or a line loss for a different energy costing period. This new column looks up the correct line loss value based on the energy strategy chosen for the measure, and then applies it to the avoided energy and energy DRIPE benefits.

7. Other Modifications

We made a few other modifications to the EE Model to accommodate DR measures in addition to the adjustments explained above.

Demand Lookups tab

In the EE Model, the "DemandLookups" tab provides energy and demand profiles for different types of efficiency measures, using a load shape ID to identify each profile. The tab includes energy load shapes by costing period (summer and winter peak and off-peak), max demand factors for converting kWh to kW, and summer and winter coincident factors. The values are based on evaluation studies.

We updated this tab to be specific to DR measures rather than energy efficiency measures. We populated energy load shapes and coincident factors for four DR load shape profiles—summer peak, summer charging, winter peak, winter charging—based on the expected operation of currently proposed DR measures. For example, the summer peak profile assumes 100 percent summer on-peak energy savings and a 100 percent summer capacity coincident factor. We assume kWh and kW savings will be technology-specific rather than based on a max demand factor, and therefore we did not include a max demand factor on the "Demand Lookups" tab. The utilities can add other DR load shapes over time, as measures are evaluated and new measures are added to the model.[27]

AESC tab

As explained in *3. Avoided Capacity*, the AESC Study provides cleared and uncleared values for capacity, capacity DRIPE, and reliability. The EE Model only allowed the calculations tabs to reference the weighted average of cleared and uncleared values. For the DR Model, we added columns to show cleared, uncleared, and the weighted average for capacity, and capacity DRIPE, and reliability. The new columns show these values in terms of retail rates, in nominal dollars, and annually and cumulative.

Output tables

In the EE Model, the "Att 1" tabs summarized costs, savings, benefits, cost-effectiveness, and performance incentives by energy efficiency program.

For the DR Model, we adjusted the output tables on the "Att 1" tabs to show only those programs that are calculated in the DR Model, rather than include all energy efficiency programs. We also summarized values for each year of the three-year plan, rather than a single year of the plan.

Lookups tab

Consistent with the EE Model, the "Lookups" tab lists inputs that are used throughout the model, such as program years, discount rates, and line losses. In the DR Model, we kept this tab exactly consistent with its equivalent tab in the EE Model. The one adjustment we made was to set the amount of capacity bid into the FCM to 0 percent, which could be adjusted overtime as the utilities bid more DR resources into the FCM.

Deleted tabs

The EE Model included output summary tabs that were not relevant for DR measures. As such, we removed those tabs, which are as follows.

- The "MMBTU by Fuel Type" tab, which summarized annual and lifetime savings for other fuels by customer sector. There are no other fuel savings for DR measures.
- The "Att 2" and "Att" 4 tabs, which summarized historical measure data by energy efficiency program. There is no historical data for DR measures because this is the first time the utilities are offering DR measures.

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[27] The energy load shape for DR measures is not used to calculate energy benefits like with energy efficiency measures. It is used to calculate savings by costing period on the calculations tab, and to calculate benefits from environmental externalities.

Attachment B: 2019 Commercial and Industrial Demand Reduction Initiative
January 28, 2019

2019

2019 Commercial and Industrial Demand Reduction Initiative

Jointly Submitted by

Public Service Company of New Hampshire d/b/a Eversource Energy

Unitil Energy Systems, Inc.

NHPUC Docket DE 17-136
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1.0 NH Commercial & Industrial ("C&I") Active Demand Reduction Initiative Background

Eversource, Liberty, NH Electric Cooperative and Unitil ("NH Utilities") have been actively monitoring multiple demand management demonstrations from other states, with the goal to leverage understanding of potential markets and methodologies that could be adopted in New Hampshire. The 2018-2020 Statewide Energy Efficiency Plan (the approved and amended version of that plan was submitted on January 15, 2019) includes a section on Capacity Demand Management that describes many of the demonstrations that the NH Utilities are monitoring.

One approach that has proven successful, resulting in cost-effective demand reductions, in other states is Commercial and Industrial ("C&I") active demand reduction. The C&I active demand reduction demonstration efforts and program offerings in Massachusetts, Connecticut, and Rhode Island typically include customers with interval meters and demand charges, with peak demand of 250 kW or higher, and with the ability to curtail 50 kW. Under an active demand reduction approach, customers agree to respond to an event call targeting conditions that typically result in ISO-NE system peak reductions through curtailment service providers ("CSPs")—vendors who identify curtailable load, enroll customers, manage curtailment events, and calculate payments. The customer is incentivized to respond to event calls using performance-based incentives that are determined by measuring performance against a baseline that is established in alignment with ISO-NE methodology. This approach is technology agnostic and can utilize single end-use control strategies or a multitude of approaches that can reduce demand when an event is called. In the New England demonstrations, customers used lighting with both manual and automated controls, HVAC with both manual and automated controls, process loads, scheduling changes, excess Combined Heat & Power (CHP) capacity, and energy storage to reduce demand. The demonstration projects utilize a "pay for performance" program design, meaning that participants and CSPs are only paid for their verified load reductions. This ensures that utility customers are protected from non-performance, as no upfront incentives are paid.

Eversource and Unitil's ("Utilities") active demand reduction offering for 2019 is based on the recently evaluated C&I active demand reduction demonstration efforts from across Massachusetts, Connecticut, and Rhode Island. Based on the success of these regional demonstration efforts, the Utilities will offer incentives to reduce demand at key times to realize customer value and system benefits mainly tied to avoided peak demand as quantified in the regional Avoided Energy Supply Cost (AESC) study.

2.0 NH C&I Active Demand Reduction Initiative

The model for the New Hampshire C&I Active Demand Reduction Initiative are the MA 2016-2018 C&I Interruptible Load Curtailment demonstration projects targeting demand during summer peak (June 1 to September 30). This offering is technology agnostic and provides an incentive for verifiable shedding of load in response to a signal or communication from the Utilities coinciding with ISO-NE system peak conditions. Customers are incentivized based on their average performance during events. Typical technologies or strategies used to curtail load may include:

- energy management systems,
- building management systems,
- software and controls,
- HVAC controls,
- lighting with controls (manual, networked system or integrated),
- process offsets,
- battery storage
- any open automated demand response (OpenADR) compliant technology,
- startup sequencing, and
- other customer facility specific approaches.

Customers can use any technology or strategy at their disposal and earn an incentive based on their curtailment performance. In essence, the incentive equals the customers' opportunity cost – if it makes sense for a customer to shed load for the incentive price offered by the Utilities, then the customer will curtail. Large C&I customers that are subject to demand charges and/or direct capacity charges (determined by Installed Capacity ("ICAP") tags) with the ability to control lighting, comfort, and/or process loads, can use this demand reduction performance offering to earn incentives by altering their operations when called upon by the Utilities. The incentive, combined with any ISO-NE capacity charge reduction and demand charge reduction, round out a compelling package for customers to adjust operations when called upon.

The Utilities anticipate that there will be between 20-40 hours' worth of calls each summer, representing approximately ten discrete calls. The program will only be offered during the summer months, because that is typically when the ISO-NE system peak occurs and the value for offsetting capacity costs is likely the highest. To maximize customer participation, it is important to minimize operational interference at a customer's facility, and dispatching for 20-40 hours, or less, is likely to result in predictable and sustainable participation levels.

3.0 Delivery Pathways

This fully-integrated initiative uses CSPs and the Utilities' existing energy efficiency implementation teams to assess curtailment opportunities at customers' facilities and deliver curtailment services to those who enroll. The utility Program Administrators will leverage the existing consultative sales approach employed for large customers to market to and recruit customers. CSPs will then identify specific curtailment opportunities, as well as demand charge and ICAP tag management opportunities, and present complete curtailment proposals to the customers. The demand charge and ICAP tag management provide opportunities for direct bill savings to customers.

This fully integrated approach relies on sales delivery teams promoting efficiency and active demand offerings to customers as they assess opportunities at customer facilities. Using the existing efficiency delivery apparatus is key to the growth of NH C&I active demand reduction. The robust relationships the Utilities have with the target customers (typically large electric customers with interval meters and demand charges) have been critical to the demonstration success in Massachusetts and the Utilities anticipate they will be the source of progress on this New Hampshire initiative.

Customers and CSPs respond to dispatch signals or criteria specified by the Utilities, generally using a system peak trigger. Events will be called the day before curtailment is needed. The core model remains focused on reducing demand during summer peak events typically targeting fewer than twenty hours per summer, although the actual number of dispatch hours may be higher. The goal of the offering is to call events at times of peak energy use. For customers participating in ISO-NE demand response markets, ISO-NE event days will be excluded from baseline calculations. The approach is structured to avoid interfering with the ISO-NE programs or penalizing customers for participating in both programs.

4.0 Anticipated Project Benefits

The NH C&I Active Demand Reduction Initiative will seek to confirm hypothesized benefits about reducing usage during ISO-NE system peak times. If this demonstration project is continued over multiple years or is developed into a program, the Utilities will be able to use ISO data to see if New Hampshire's share of overall peak capacity has been reduced over time.

This offering will be different than the ISO-NE demand response program and will be focused on generating different types of benefits. The ISO-NE demand response program has historically been a program centered around reliability, which is a FERC-designated responsibility of ISO-NE. Although direct demand response calls from ISO-NE for reliability have essentially been phased out, the ISO-NE program still functions, and its main goal is to maintain system reliability. In this Initiative, the Utilities will be primarily focused on providing economic benefits for customers.

The Utilities will focus on reducing capacity and possibly transmission costs through peak demand reduction, which is not a primary goal of ISO-NE. For example, ISO-NE historically would not need to call an event during the peak hour if there were adequate supply. However, each of the Utilities may choose to call an event during the peak hour in order to lower ICAP tags and mitigate capacity costs. Customers will be able to make use of both programs if, as is anticipated, they are dispatched at different times. It is not a requirement to participate in ISO-NE's demand response program in order to participate in the Utilities' proposed program. In the rare instance when both the Utilities and ISO-NE dispatch at the same time, the ISO-NE dispatch will take priority and the customer's dispatch will not factor into the performance calculation for the Utilities' program, ensuring that the customer would not receive an additional incentive nor be penalized from the Utilities for the same dispatch.

5.0 Customer Incentive Calculation

The incentive for the interruptible load curtailment will be based on the average performance of the customer during the called hours, multiplied by the payout rate. For example, for summer curtailment, the Utilities may call for reductions during 10 hours in a given year. A customer's hypothetical load reductions during those hours are presented below:

Table 5.1: Example load reductions

Reductions in kW										
Hour 1	Hour 2	Hour 3	Hour 4	Hour 5	Hour 6	Hour 7	Hour 8	Hour 9	Hour 10	Average
100	80	90	95	100	100	90	0	90	80	82.5

In this example, the average customer performance across the 10 called hours is an 82.5 kW reduction. The customer and CSP will split the performance incentive, which in this example would be calculated as 82.5 (average kW reduction) x $35 (illustrative payout rate combined for both) = $2,887.50. This incentive would be paid out on an annual basis and would be re-calculated each year based on that year's performance, considering any adjustments made to the payout rate. There are no direct penalties for non-performance. However, non-performance will impact the performance calculation for a customer and thus the level of incentive. Hour 8 in the table above is an example of non-performance during a called event-hour. There is no direct penalty but the non-performance in that hour impacts the overall average reduction, which is the basis for the incentive calculation.

6.0 Baseline Calculation Methodology

A baseline will be calculated as described below for each C&I customer participating in the program. The baseline will be calculated at the retail delivery point. In order to participate in the program, the C&I customer must have an interval meter recording load or any output pushed back to the distribution system—i.e., "net supply"—for each interval. Solely for the purpose of this demand reduction effort, respondents may propose metering at a retail billing point that does not utilize a utility interval meter but is capable of recording load or net supply at appropriate intervals.

The baseline will be calculated for each non-holiday weekday interval during the summer cooling season, when the ISO-NE system peak generally occurs. The summer season for purposes of the Utilities' program will be June 1 through September 30th. The only weekday summer holidays are Independence Day and Labor Day. If Independence Day falls on a Saturday, the holiday is observed on Friday, July 3; if the holiday falls on a Sunday, the holiday is observed on Monday, July 5. A CSP or the C&I customer is restricted from taking any action to create or maintain a baseline that exceeds the typical electricity consumption levels that would be expected in the normal course of business for the customer. The program will be designed to minimize this risk and any customer/CSP found to be engaging in this practice will be removed from the program.

If the participating C&I customer produces net supply (i.e., pushes back energy at the retail delivery point) in an interval, that net supply will be used in the baseline calculations for that interval as representative of normal operating practice.

A non-holiday weekday baseline in each interval is equal to the average of the customer's meter data for the same interval from 10 prior non-holiday weekdays, as follows:

- For a customer without a non-holiday weekday baseline, the initial non-holiday weekday baseline will be created using meter data from the first 10 consecutive non-holiday weekdays with a complete set of interval meter data. This interval meter data will either be from a period just prior to the start of the customer's enrollment in the program or for the first 10 consecutive non-holiday weekdays once enrolled in the program. The customer is not permitted to participate in any activation until a baseline can be calculated. This includes activations from ISO-NE dispatch.
- For a customer that has established a non-holiday weekday baseline, the baseline is calculated each day using meter data from:
    - the 10 most recent of the previous 30 non-holiday weekdays, excluding days during which: (1) the customer received an activation instruction or (2) the customer was on a facility scheduled shutdown (as described later);
    - if there are fewer than 10 such days, then meter data from additional days will be used (until a total of 10 days have been identified) including, first, the most recent days during which the customer received an activation instruction and, second, the most recent days during which the customer was on a facility scheduled shutdown.

A facility scheduled shutdown is a reduction in demand resulting from a scheduled plant shutdown or scheduled maintenance of energy consuming equipment that would have normally responded to a demand response event during the activation period. A scheduled plant shutdown may be no shorter than a single calendar day and the total duration of the scheduled plant shutdown per summer cooling season or winter heating season may not exceed 14 calendar days. A facility in shutdown will not have those days counted toward baseline unless the requisite 10 days cannot be met with days with normal operations. Only the first day of a scheduled plant shutdown may be counted as performance during a program dispatch. Additional days in shutdown will not count towards positive performance.

7.0 Costs and Savings

Eversource anticipates spending $250,000 in 2019 to generate 5 MW of summer demand savings. Unitil anticipates spending $90,000 in 2019 to generate 1.8 MW of savings (included in the Large Business Energy Solutions budget). This equates to $50/kW. That budgetary figure is inclusive of incentives, vendor costs, software costs, and utility program delivery costs. As mentioned earlier, this is a "pay for performance" program design, meaning that none of the incentive or vendor costs will be paid unless there are verifiable and measurable load reductions.

Costs for the Demand Reduction Initiative are included in the benefit cost model and detail attachments provided in the DE 17-136 Update Plan Compliance Filing made on January 15, 2019. Because this is a pilot initiative, the savings are not included in the benefit cost model for 2019.

8.0 Next Steps

The Utilities will utilize CSPs under existing contracts through their respective Massachusetts demand response programs and will begin recruiting New Hampshire customers for participation immediately following approval to prepare for the summer 2019 season. The Utilities will provide updates on the NH C&I Active Demand Reduction Initiative as appropriate at DE 17-136 Quarterly Meetings. All of the NH Electric Utilities will review this initiative for potential inclusion in the 2020 Update and the 2021-2023 Statewide Energy Efficiency Plan.

The NH Electric Utilities will also continue to review the results of other demonstrations approved by the Massachusetts Department of Public Utilities ("MA DPU") in D.P.U. 16-178, and programs under consideration in D.P.U. 18-117 (Fitchburg Gas and Electric, dba Unitil) and D.P.U. 18-119 (Eversource in MA) as well as other related demonstrations in Connecticut and Rhode Island. In 2018 and 2019, Eversource (MA) is deploying demand reduction demonstration offerings for battery storage, thermal storage, software and controls, and active demand response, some including upfront incentives for equipment installations. Eversource has also proposed testing the ability to manage electric vehicle charging in Massachusetts. These demonstrations are designed to test the ability of the projects to deliver cost-effective benefits to customers at scale. After the evaluation of the demonstrations, Eversource in Massachusetts will submit a report to the MA DPU with an analysis of the actual costs and benefits of each demonstration project. The NH Utilities will utilize this review and as well as demonstration results from other states and utilities to inform future potential offerings in New Hampshire.

Attachment C: Residential Active Demand Reduction Initiative

2020 Residential Active Demand Reduction Initiative

Overview

Residential active demand offerings present unique challenges for recruitment and implementation. Unlike large C&I customers, residential customers currently do not generally pay demand charges or time varying rates, and therefore have no inherent, direct incentive to decrease usage during specific peak demand periods. Peak demand reductions through active demand management can have a system benefit that reduces overall capacity and temporal-energy costs for all customers, therefore, Eversource and Unitil have designed a model for residential active demand offerings that provides incentives for peak demand reductions to capture these system benefits.

The core model for the residential direct load control offering remains focused on reducing demand during summer peak load. The design is a bring-your-own-device (BYOD) model, starting first with communicating thermostats controlling central air conditioning units and behind the meter customer owned battery storage systems. At some time in the future, additional eligible connected devices may include water heaters, pool pumps, window AC, electric vehicle chargers and other devices. Incorporation of additional devices will depend on device saturation, manufacturer concentration, and the costs associated with integrating and enabling load control on each type of device.

Eligible customers' devices will be connected to a demand response management platform through an application programming interface ("API"), a mechanism that allows two different electronic systems to exchange core data and interact in a common language. Eversource, through its contracted demand response management platform, will send a signal to the device manufacturer cloud during an event that causes the controller to reduce the demand of the connected device. Events will be called in advance, primarily in the months of June, July, August, and September. Customers can opt-out of events; however, they will be removed from the program if they regularly do not participate.

Delivery Pathways for Residential Direct Load Control Offerings

Customers with eligible technology (controllable communicating device) will be offered the opportunity to enroll in the active demand offering and incentivized to participate in demand reduction during summer peak events. Eversource and Unitil will seek to enroll both customers with devices already installed and customers installing devices through the energy efficiency delivery. By targeting customers with devices already installed, Eversource and Unitil can seek to ramp up enrollment by recruiting adopters of technology already incentivized by efficiency efforts or other means, while also seeking to expand the pool of eligible devices through energy efficiency efforts, where applicable.

Smart Thermostats

The Smart Thermostat program is proposed for customers that own a qualified thermostat controlling a central air conditioning system. Participants agree to allow for brief, limited adjustments of their thermostats during periods of peak electric demand between June 1 and September 30. There will be at least one adjustment, and a maximum of 15 adjustments per summer. Peak demand periods typically occur on especially hot days. Participation is voluntary, and customers always retain ultimate control of their thermostat.

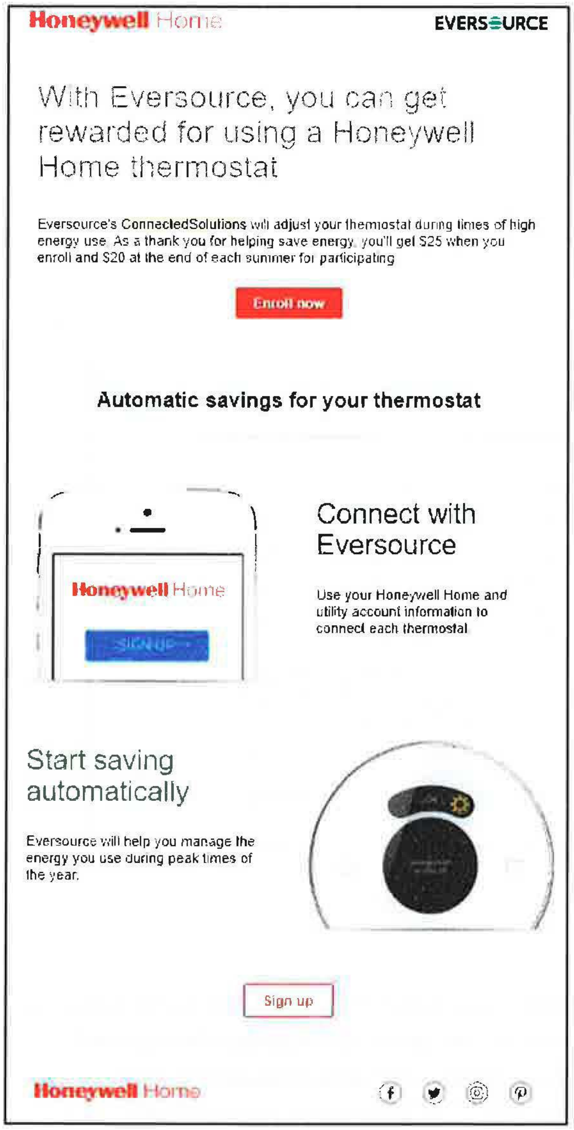
Below is the current list of qualifying thermostats. Eversource, Unitil and their partners endeavor to continuously add new devices as they become available

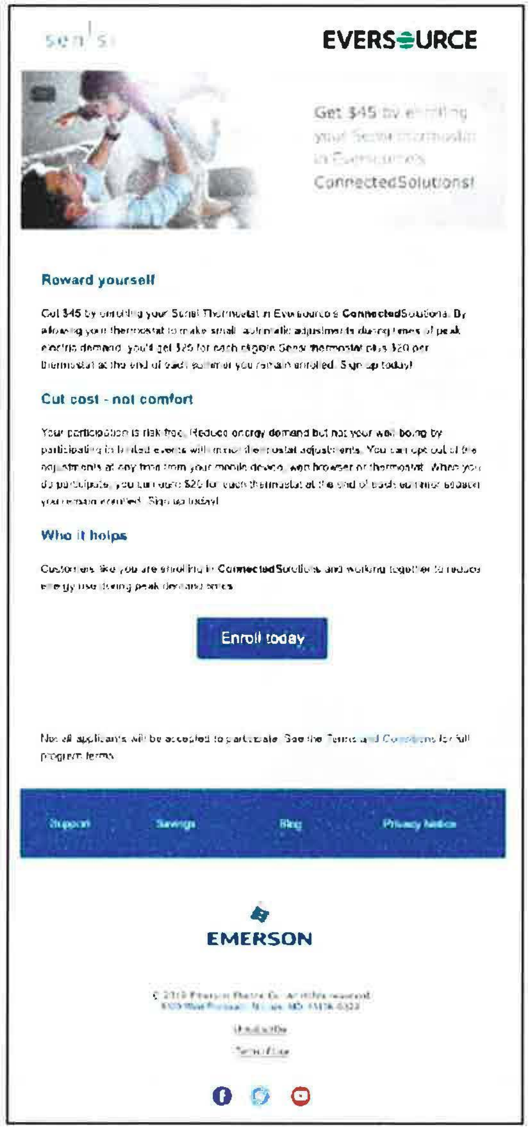
Provider	Approved Thermostats
Alarm.com	Radio Thermostat CT30, CT80, CT100; Trane ComfortLink Control; RCS Z-Wave Communicating Thermostat; GoControl Z-wave Thermostat; Alarm.com Smart Thermostat
Building36	Building 36 Intelligent Thermostat
ecobee	ecobee3, ecobee3 Lite, ecobee4, ecobee Smart Si, ecobee Smart, ecobee SmartThermostat with voice control
Emerson	Sensi™ Wi-Fi Programmable Thermostat, Sensi Touch Wi-Fi Thermostat
Honeywell Home	Wi-Fi Smart Color Thermostat, Wi-Fi 7-Day Programmable Thermostat, Wi-Fi 9000 7-Day Programmable Thermostat, 9000 Smart Thermostat, 7-Day Programmable Smart Thermostat, VisionPro 8000 Smart Thermostat, Round Smart Thermostat, T5+ Smart Thermostat, T6 Pro Smart Thermostat, T9 Smart Thermostat, T10 Smart Thermostat
Lux	LUX/GEO, LUX KONO
Nest	Nest Learning Thermostat, Nest Thermostat E
Radio Thermostat	Filtrete 3M-50, CT30, CT50, CT80
Vivint	Radio Thermostat CT100 with Vivint Go!Control Panel

Marketing & Enrollment

The utilities will work with OEMs, their own internal marketing departments, and third-party business partners to recruit and enroll customers to participate in these bring your own device demonstration projects. Eversource and Unitil successfully worked with device manufacturers in their other service territories to send targeted emails and in-app enrollment notifications to customers with existing equipment to spur enrollment. Eversource and Unitil can also implement internal marketing approaches (direct mail, utility websites, etc.).

Example of co-marketing emails:





Adjustment Details

At the start of a peak energy event, the thermostat will be automatically adjusted no more than 4 degrees above the current temperature. The adjustment will typically last 3 hours, and will occur between 2 p.m. and 7 p.m. Once the temperature adjustment is over, the thermostat will return to its normal set point and/or schedule.

In some cases, the thermostat might be adjusted down 3 degrees prior to an adjustment event to pre-cool. The pre-cool helps customers to maintain comfort throughout the duration of the event.

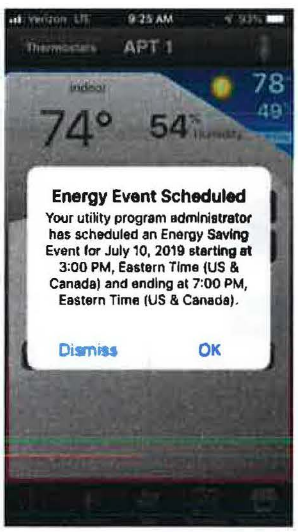
Customers can opt out of an event at any time from a mobile device, web browser, or thermostat.

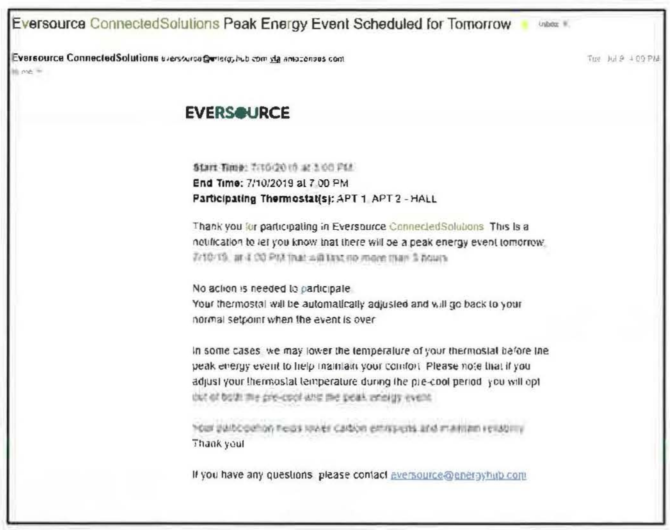
Incentive Information

Participants will receive one $25 to $35 e-gift card per device after being accepted into the program and another $20 to $35 e-gift card per device at the end of each summer season for participating.

Event Notification

Customers may be notified of events via mobile device in-app, email message, or directly on device. Below are examples of in-app & email notifications:





Eversource ConnectedSolutions Peak Energy Event Scheduled for Tomorrow

Eversource ConnectedSolutions

EVERSOURCE

End Time: 7/10/2019 at 7:00 PM
Participating Thermostat(s): APT 1, APT 2 - HALL

Thank you for participating in Eversource ConnectedSolutions. This is a notification to let you know that there will be a peak energy event tomorrow,

No action is needed to participate.
Your thermostat will be automatically adjusted and will go back to your normal setpoint when the event is over.

In some cases, we may lower the temperature of your thermostat before the peak energy event to help maintain your comfort. Please note that if you adjust your thermostat temperature during the pre-cool period, you will opt

Thank you!

If you have any questions, please contact eversource@energyhub.com

Performance Calculation

As stated above, the customer incentive is solely based upon successful enrollment and participation in the program. Calculation of performance (kW) is calculated by the Demand Response Management System platform for each event. This methodology will be verified by 3rd party evaluations. The calculation is based on AC run time data provided by each individual thermostat and nominal AC size. This is compared to a 10-of-10 ISO-NE baseline.

Residential Storage

Eversource and Unitil are proposing a residential storage offering that is specifically tailored to build on the lessons learned from successful pay for performance active demand demonstrations in other states. This program would encourage the performance of energy storage by providing incentives higher than other Direct Load Control offerings. This higher incentive assumes that storage performance does not impact customer comfort, will be more robust, more available, less likely to be overridden and thus more reliable as a resource overall.

By using a pay for performance approach, Eversource and Unitil will be able to utilize incentive funds in a manner that maximizes the benefits of peak demand reduction, while providing a predictable revenue stream to customers. The incentive levels under this program are designed to encourage performance of storage, which comparatively has a high upfront cost but also provides opportunities for demand reduction without significant interference with customer comfort and operations. Under this offering, customers will be incentivized to decrease demand through the discharge of energy from storage in response to a signal or communication from the Utilities' intermediary partner(s). Lowering daily summer peak demand will have an impact on overall capacity requirements. Storage provides an opportunity to secure predictable demand reductions without the potentially significant and adverse impacts on customers of shedding demand on a frequent basis through other means.

Delivery Pathways for Residential Storage Offerings

The Residential Storage Performance offering recognizes that residential customers do not have the same value proposition for storage as a Large C&I customer with demand charges, direct capacity costs, and time of use rates. Eversource and Unitil anticipate that many energy storage installations by residential customers will be paired with solar PV systems. The overall offering balances giving customers flexibility in using energy storage systems for multiple purposes such as backup power during outages and ensuring that ratepayer funds are used in a manner that provides substantial peak demand reductions.

Eversource and Unitil will reach customers by partnering with storage device manufacturers and local project developers. The utilities also plan significant marketing and educational sessions directed towards customers to educate them on these advanced energy topics.

Dispatch

Eversource and Unitil will be responsible for scheduling the dispatch of storage devices. It will be the Utilities' responsibility to decide when the dispatch should occur. From a technical perspective, it is not envisioned that Eversource or Unitil will have direct access to the storage units themselves. Rather, an intermediary, either the storage original equipment manufacturer (OEM) or a project developer, will have the direct software access to the storage unit that physically controls the dispatch. Eversource will use dispatch software platforms to a send a signal to the battery system controllers' cloud to carry out the desired dispatch instructions to the discreet device. Customers or the operator of the device always retains the right to opt out of any event dispatch at any time but will receive a zero towards its annual average for that event.

Program Details

Residential Storage Program Details	
Incentive per average kW used	$225 to $350
Season Dates	June 1- September 30
Number of Events	30-60
Event Duration	3 hours
Timing	2:00 pm - 7:00 pm
Notifications	Before every event

Storage Incentive

The storage incentive is intended to motivate customers to deliver peak demand reductions from storage assets to mitigate the costs of peak demand for all customers. The incentive is not specifically intended to offset financial losses associated with cycling, charging, or other uses. Those losses are a cost, among others, that customers must consider when planning their investments, much like increased fuel use with the installation of a combined heat and power system. The incentive is meant to provide a guaranteed revenue stream, tied to performance at system peak, for customers and developers that will encourage storage units to be developed and installed while protecting all customers from the risk that storage assets will not produce system benefits.

The incentive for the Storage dispatch will be based on the average performance of the customer during the called hours multiplied by the payout rate. The output performance of the battery storage system is measured directly at the storage devices themselves. As stated above, Eversource and Unitil plan to partner with the battery OEMs and developers who have access to this device data. The Utilities will receive this data from the devices' onboard telemetry without the need for added metering costs.

For this example, for summer Storage Daily Dispatch, the Program Administrators have called 10 events over the summer season (actual program range is 30 to 60 events). The events were a duration of 3 hours each. And the incentive was $225 per average annual seasonal kW reduction. Thus, there were 30 total event hours during this example season. This customer's hypothetical load reductions come from an 8 kW (nominal nameplate rating) system. The performance during those event hours are presented below:

	kW Performance by Hour During Event		
	Hour 1	**Hour 2**	**Hour 3**
Event 1	6	7	8
Event 2	8	7	6
Event 3	5	5	6
Event 4	6	7	8
Event 5	0	0	0
Event 6	5	8	6
Event 7	5	7	7
Event 8	6	8	8
Event 9	5	7	8
Event 10	6	8	7

Even though the nominal rating of the storage system is 8kw, it is expected that the output may not be 8kW at all times. This customer has also elected to Opt Out of Event #5 as reflected in the data. The average customer performance across those 30 hours was a 6 kW reduction. The customer would be paid 6 (average kW reduction) x $225 (payout rate for summer daily storage dispatch) = $1,350. This incentive would be paid after each summer season to the customer or their designee. As these programs carry on, this customer would be eligible to participate in any subsequent season with a fresh start.

Attachment D: Eversource Demand Response Benefit Cost Models

Attachment E: Unitil Demand Response Benefit Cost Models

Docket No. DE 17-136

These attachments have been deliberately excluded from hard copy submission due to the complexity and size of each of the four workbooks in native Microsoft Excel format. Both attachments have been submitted in their entirety electronically.