Efficiency Maine Innovation Pilot Final Report Addendum
Summary of major findings 12/28/20

Executive Summary

In response to an RFP issued by the Efficiency Maine Trust (RFP EM-011-2018) for Load Management Innovation Pilots, ReVision Energy has deployed and operated a fleet of residential Distributed Energy Resources (DERs) to assess the viability of aggregated control of those devices for demand flexibility. The DER fleet consisted of residential Air Source Heat Pumps, Heat Pump Water Heathers, Electric Vehicle Chargers and Batteries and were controlled to reduce peak load, carbon pollution and respond to other hypothetical third-party control interventions. Using remote electronic signals via the internet to control these customer owned devices during various times of day throughout the year to simulate various grid scenarios, we evaluated both the technical and economic potential of such a program, as well as customer's willingness to participate in it. Overall customer acceptance/satisfaction was high and the technical and financial potential of aggregated DER as load flexibility resource was affirmed for all device types, with residential battery storage systems showing the greatest near term potential to shave peak load and reduce ratepayer costs for the both the owner of the storage device and all other ratepaying customers of the same utility company. A final report was delivered to EM on 10/12/20. This Addendum contains a summary of the major findings articulated in that report.

Testing highlights and Insights

Though the control logic and grid conditions simulated varied by month, the DER pilot overall yielded some common high-level takeaways:

1- Value of flexibility varies by season and by device type with Battery Energy Storage and EV chargers representing the most substantial near term opportunity for DER aggregation and control.

- Though batteries are the most expensive of the devices in our fleet, they also were far and away the largest and most flexibly controllable devices overall. With a few exceptions, battery availability is not dependent on customer behavior and so the batteries tend to always be available when called upon. Batteries can also shift a significant load, as much as 5 kW peak and up to 10,000 watt hours for a single event. As a result of their high power and high availability, a single battery system is as effective at load shifting as roughly 30 to 40 air source heat pumps combined. In light of the not insubstantial effort involved in customer acquisition and communications/controls cost per device, the battery energy storage system represent the highest value near term opportunity for distributed load flexibility.
- EV Chargers are also a very significant load, but unlike battery systems, their availability in our pilot was very low. This is particularly true of residential chargers which tend to have a relatively low duty cycle and even lower peak coincidence. In spite of this, given the scale of expected EV adoption in the coming 5 years and the magnitude of the load, EV chargers are certainly worth controlling because they represent such a significant load both for an individual household and for a future fully electrified economy. A

charger program that includes both residential and commercial/workplace charging would likely have a more diverse load pattern and thus higher demand flexibility value.

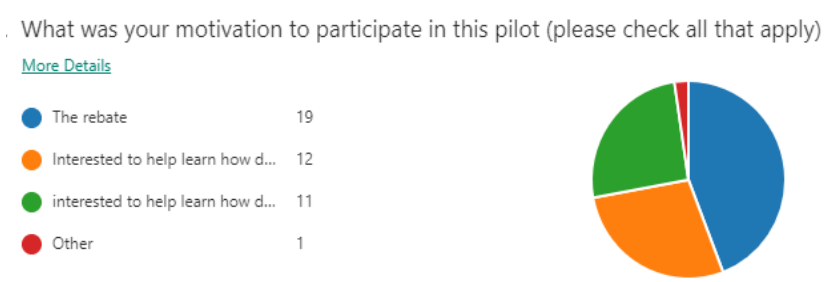
2- Heat Pumps and Heat Pump water heaters were also effective at shaping load, but given the lower peak coincidence/availability and relatively small magnitude of shiftable load per device, they should be a lower priority for future program development.

- ASHP and HPWH may also be useful distributed load shaping resources, but only if the cost/effort of aggregating and controlling them is small. As more of these devices are natively 'smart' (i.e. network connected), the cost of aggregation and control will continue to come down and they should be considered in future DER aggregation programs.
- Air Source Heat Pumps are not yet very useful as summertime load management in Maine because not that many of them (<25%) are consistently used in cooling mode. The mini splits heat pumps that were operating proved to be fairly responsive to call for load shedding, but because the heat pumps are very efficient, the actual load shifted per device is small (a few hundred watt hours per responding device).
- Water heaters have traditionally been considered as the low hanging fruit of residential demand response programs, but heat pump water heaters are so efficient that the magnitude of the shifted load is only 1/10 of a conventional electric water heater. In our pilot, Heat Pump water heaters proved relatively easy to control with minimal impact on customers. As with mini splits, HPWH's are very efficient in heat pump mode and so the shifted load per device is also relatively small (few hundred watts hours per responding device).

3 -Customer motivation varied but was not purely financial. While 100% of customers who responded to our post project survey (19 of 19) indicated that the financial rebate was part of their motivation to participate in the Pilot, a majority also reported that they were motivated by:

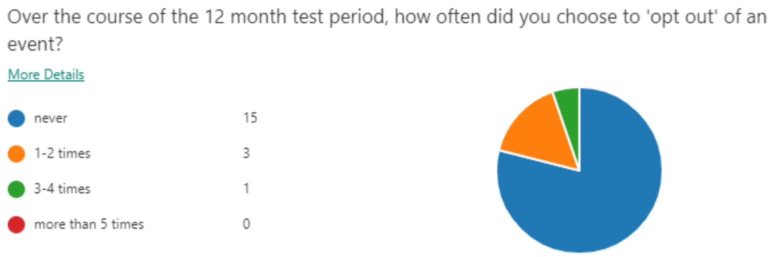
"Interested to help learn how distributed energy resources can lower costs for all ratepayers" = 12 of 19

"Interested to help learn how distributed energy resources can help integrate higher levels of renewables on the grid" = 11 of 19

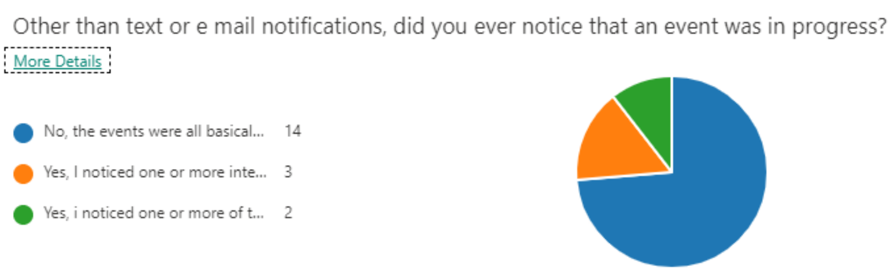


This is a useful takeaway to help inform marketing decisions should Efficiency Maine pursue similar programs in the future.

4- Customer acceptance was good overall and opt out rates were low throughout the test period. The data from the VP portal and self-reported 'opt out' rates for the program were low throughout the year, with most customers never opting out of an event at all.



For those customers that did opt out, the reasons provided ranged from a desire to maintain control over the device at that particular time, to confusion or customer error. Only a single respondent indicated that one time they "opted out part-way through as the home was becoming uncomfortable" (hot, humid day). But in general, when asked whether the control interventions affected them, most indicated that they either didn't notice the events at all (14 of 19) or that they noticed the events but were never uncomfortable (3 of 19).



Overall, customers indicated a strong interest/willingness to participate in a similar program in the future:

If offered an opportunity in the future to enroll a device (water heater, heat pump, battery, EV charger) in a smart grid program in exchange for monetary compensation, how likely are you do to do so? (1= Definitely not ... 5= Definitely would participate)

More Details

19
Responses

4.26
Average Number

5- Communications relying on customer internet is generally viable, if imperfect. One of the most substantial challenges of controlling a fleet of distributed energy resources is maintaining consistent communication with all devices. While some DER control programs rely on a dedicated communication channel (typically either cellular, utility power line communication or utility AMI systems), most depend on the customer's local network and internet connectivity. While relatively inexpensive, this comes with some challenges as customer internet quality varies widely, as does their technical sophistication if asked to troubleshoot or correct communication challenges.

It is worth noting that Connectivity/Bandwidth to the customer's home was almost never an issue; virtually all device communication challenges occurred either on the customer side (local area network issues), or at the manufacturer server (stability of device connections and consistency of API connection to Virtual Peaker). The latter of these will naturally improve as hardware and software matures and as programs scale. The former will continue to be a challenge, though a few key lessons learned for future programs include:

-Though more costly up front, providing a hard wired connection to the local area network rather than relying on a wifi network is more reliable and consistent. Wifi network names change, passwords are updated, etc while hard wired connections stay consistent.

-One substantial benefit of controlling devices via API connection to the native device control app server is that because the customer is presumably also using the app for control, they are likely to identify and be motivated to repair connectivity issues.

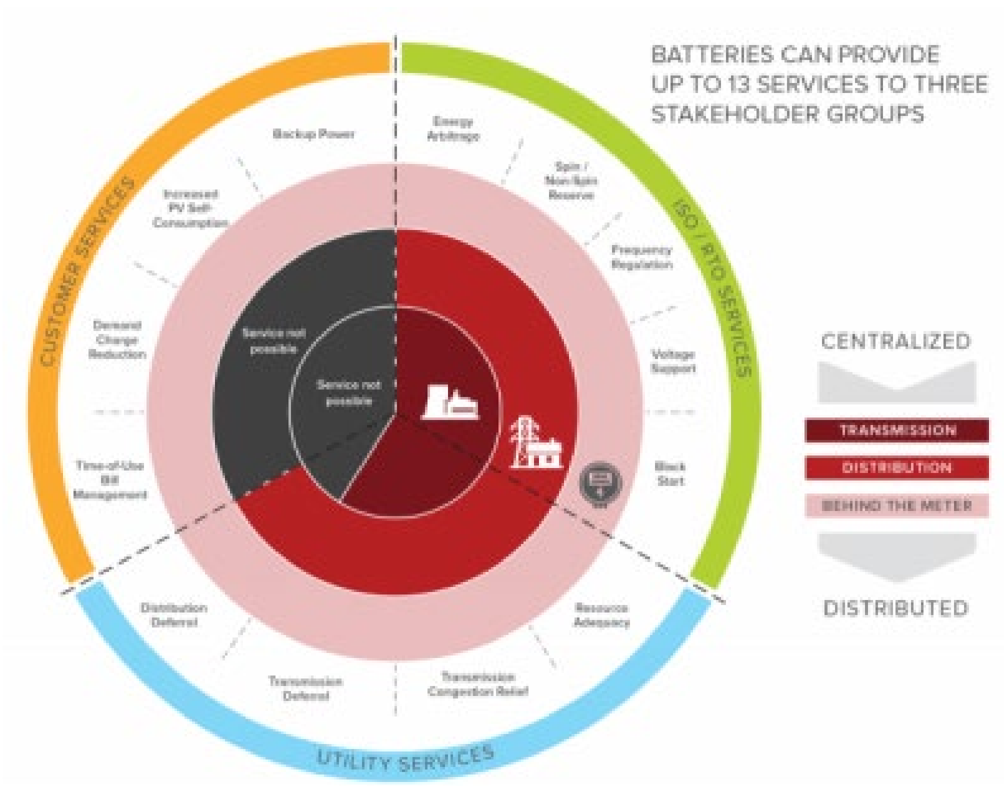
-it is important for fleet operators to continually troubleshoot connectivity issues with devices, so they do not just crop up during high value/high performance risk events. With this small pilot, this oversight could be done manually, but in larger programs that oversight needs to be automated. This is particularly important for programs which expect to derive substantial revenue/savings from low occurrence and high value markets such as the Capacity market, where just a single hour or two drive financial performance for the entire year.

-Programs that pay for performance, either based on performance during discrete events, or in aggregate as in this program (with part of the rebate reserved for payment at the end of the program), help to provide incentives for customers to keep devices connected.

-Since connectivity and control makes up a substantial portion of overall operating costs for a DER aggregation provider, it makes sense to focus future programs on those devices that provide the largest load flexibility pre connected device, which were battery energy storage and EV chargers.

<u>Calculating financial benefits</u>:

The value of an aggregated demand flexibility resource is a function of the devices availability, as well as its shiftable power (in watts) and energy (in watt-hours). As detailed in the pilot final report, shifting load or aggregated control of distributed battery systems can deliver ratepayer value in up to thirteen distinct categories, with four of them accruing to the individual customer (Backup Power, Increased Pv Self Consumption, Demand charge reduction, Time of Use Bill Management) and nine of them according to utility or ISO customers generally (Energy Arbitrage, spin/Non-spin reserves, frequency regulation, voltage support, black start, resource adequacy, Transmission congestion relief, Transmission Deferral, Distribution Deferral).



While recent FERC order #2222 promises to make a number of the ISO/RTO Service value streams accessible to aggregators in the coming years, the current value proposition for aggregation depends primarily on two value streams:

1- monetizing the Capacity (resource adequacy) value of the batteries to reduce rate payer capacity costs by lowering overall customer demand at times of system peak
2- monetizing the transmission peak reduction (RNS peaks) to reduce Maine's shared transmission cost obligations.

1- Capacity Peak Value

Most DER pilots focus primarily on capturing the value of reduced generation capacity costs. This is because Capacity is traditionally the second largest portion of a customer's energy supply bill and is relatively easy to target because the capacity peak has been fairly predictable in New England for many years.

The clearing price of the Forward Capacity Auctions run by ISO new England has varied considerably over the last few years, in part because of changes in the generation fleet and in part because of changes made by the ISO in how they conduct those auctions. This volatility has made it difficult to predict the future value of the Capacity of controllable loads and even the AESC has had to make substantial revisions to previous estimates to reflect the changing market. In the 2018 report, the authors calculate that "a load reduction in the summer of 2018 is worth 12 times the 2018/2019 clearing price, or $118/kW, spread over that period." Looking forward 15 years, AESC develops a levelized estimate which is $6.42/kw/mo (or $77.04/kw per year). The table below uses this lower, levelized cost and reflects the Capacity reduction and value by device type:

	A	B	C	D	E	F
1	**Device**	**peak W per available device**	**% operating**	**15 year levelized Capacity value ($/kw/mo)**	**15 year Capacity value of single available smart device (NPV)**	**15 year Capacity value of all devices (NPV)**
2	Heat Pump Water heater	400	20%	$77.04	$369.79	$73.96
3	Air Source heat Pump	350	25%	$77.04	$323.57	$80.89
4	EV Charger	7000	25%	$77.04	$6,471.36	$1,617.84
5	Battery Storage	5000	100%	$77.04	$4,622.40	$4,622.40

Note that the average value of the device (column F) is impacted substantially by the fraction of the devices that are operating or available concurrent with the peak (column C). The estimates of available/operating devices in the table is based on our aggregate experience in this pilot project but given the significant impact on actual value these estimates warrant additional investigation.

Capacity DRIPE

When a demand side resource, such as the DER fleet, successfully targets the capacity peak and thus reduces the capacity demand, that reduction not only eliminates the direct demand but reduces the cost of all remaining capacity as well. This effect is known as Demand Reduction Induced Price Effect or DRIPE, which refers to the reduction in prices in the wholesale markets resulting from the reduction in demand in those markets due to the impact of efficiency and/or demand response programs. DRIPE affects both wholesale energy and capacity markets though for this analysis we include only Capacity DRIPE. As with capacity value, we use the 2018 AESC report to develop a reasonable estimate for value of Capacity DRIPE for each device type. The AESC calculates the value of Capacity DRIPE for both resources that are bid into the FCM and for unbid resources. Interestingly, the report finds that "Capacity DRIPE for un-bid resources is approximately two times higher than that of bid capacity DRIPE, but benefits accrue many years later. We find that un-bid DRIPE is worth more than bid DRIPE due to changes in capacity market fundamentals and different DRIPE effect timeframe." Consistent with the analysis in that report, we utilize a 10 year levelized number rather than a 15 year one to reflect the short time duration of DRIPE impacts.

The 10 year levelized Value of Capacity DRIPE for resources not bid into the FCM by AESC is $311.01 per kw/year. The table below uses this levelized cost and reflects this Capacity DRIPE value by device type:

Capacity Dripe

Device	peak W per available device	% operating	10 year levelized Capacity value ($/kw/yr)	10 year Capacity value of single available smart device (NPV)	10 year Capacity value of all devices (NPV)
Heat Pump Water heater	400	20%	$311.01	$124.40	$24.88
Air Source heat Pump	350	25%	$311.01	$108.85	$27.21
EV Charger	7000	25%	$311.01	$2,177.07	$544.27
Battery Storage	5000	100%	$311.01	$1,555.05	$1,555.05

Note: As a function of the way in which ISO NE ratepayers share costs, ME ratepayers actually realize only about 8% of this total, with the balance being savings to other New England ratepayers in proportion to their peak capacity payment obligations. For the sake of this analysis we felt it was appropriate to use the region wide ratepayer savings whether they accrue inside or outside the state.

2- Transmission cost savings (RNS Savings)

In addition to reducing the required generation capacity, shaping load to reduce peaks also has an effect on the cost of transporting that electricity from generators to consumers. Those costs include both the shared regional transmission investment (Pool transmission facilities), as well as the local transmission and distribution costs. Per ISO new England, Pool Transmission Facilities (PTF) “are those facilities owned by participating transmission owners that meet the criteria specified in the Open Access Transmission Tariff and over which the ISO has operating authority. Generally, PTFs are those rated 69 kV or above required to allow energy from significant power sources to move freely on New England’s transmission system.” The use of those PTF to move electricity within the new England region is known as the Regional Network Service or RNS. Though the cost of the RNS is shared by New England customers according to their Monthly Regional Network load value, or in other words, based on their load at the time of the monthly peak, the AESC report suggests that the PTF cost savings estimates should be “applied to the reduction in summer peak load, which appears to dominate ISO New England’s transmission planning.” AESC 2018 calculates an avoided cost for Pool Transmission Facilities (PTF) of $94/kW per year in 2018 dollars, which is the same number we use here.

RNS Savings

Device	peak W per available device	% operating	10 year levelized RNS savings value ($/kw-yr)	10 year RNS savings value of single available smart device (NPV)	10 year RNS savings value of all devices (NPV)
Heat Pump Water heater	400	20%	$94.00	$37.60	$7.52
Air Source heat Pump	350	25%	$94.00	$32.90	$8.23
EV Charger	7000	25%	$94.00	$658.00	$164.50
Battery Storage	5000	100%	$94.00	$470.00	$470.00

Summary

Considering only the two major value drivers detailed above (Capacity and RNS Savings), the total ten-year net present value of savings by device type is shown in the table below:

Device Type	Capacity + RNS (NPV)
Heat Pump Water heater	$106
Air Source heat Pump	$116
EV Charger	$2,327
Battery Storage	$6,647

Given the cost of customer acquisition and ongoing control/communication, it is clear that the energy storage and EV charger devices should be the highest near-term priority for aggregation and control by Efficiency Maine. While every effort should be made to access and monetize additional value as new rules are propagated under FERC order 2222, the ratepayers savings from Capacity and RNS savings alone should be sufficient for these two device types to justify an aggregation program as cost beneficial to rate payers.

We thank you for the opportunity to collaborate on this interesting and exciting pilot project. In spite of some of the challenges posed late in the year by the COVID-19 pandemic and related disruptions, the pilot has been a success and generated data and insights that we hope will be useful for Efficiency Maine and other stakeholders as you evaluate the growing potential of load flexibility from aggregated behind the meter DERs.

Thank you for your support and help during this pilot and for your leadership in Maine's clean energy transition.

Respectfully submitted:

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REVISION ENERGY

Efficiency Maine Innovation Pilot Final Report 10/19/2020

Executive Summary

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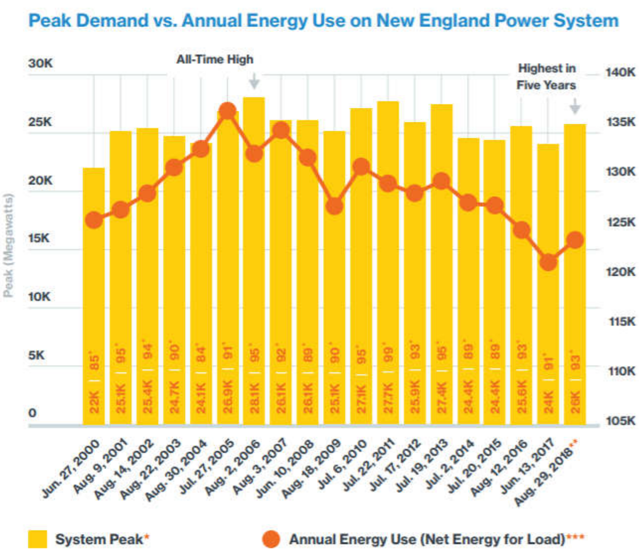
Background: the case for load flexibility

Like many efficiency program managers around the country, Efficiency Maine has recognized the need to expand their focus from helping customers to use less energy to also include the efficient use of electrical infrastructure by helping customers reduce their energy usage at peak times. This evolution is driven, in part, by the fact that while the last two decades have included a period of historically inexpensive wholesale electric costs, retail electric costs have not fallen commensurately. Among the reasons for this is that while overall annual energy consumption has fallen considerably in the last 15 years (a testament to the effectiveness of efficiency programs), peak loads have stayed relatively flat, or even continued to grow albeit at a slower rate than the previous decade.



*The sum of metered generation and metered net interchange, minus demand from pumped storage units. Starting with full market integration of demand response on June 1, 2018, this total also includes the grossed up demand-response value.

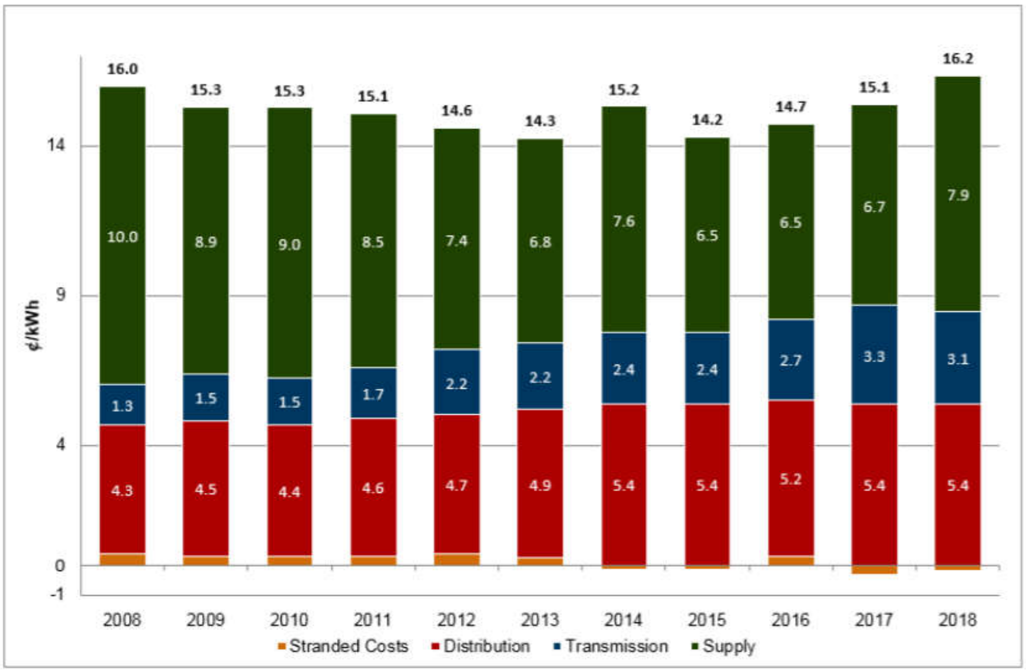
**Annual peak, as of January 2019. Values are preliminary and subject to adjustment.

***Net energy for load (NEL) is the total amount of grid electricity produced by generators in New England and imported from other regions during the year to satisfy all residential, commercial, and industrial customer demand.

Source: ISO New England, *Seasonal Peaks since 1980 Report, Hourly Real-Time System Demand Report,* and *Annual Generation and Load Data for ISO NE and the Six New England States Report.*

The reduction in overall consumption, combined with the transition to lower cost natural gas and renewable energy, has also had the effect of reducing wholesale energy prices in New England to historic lows. But customer utility bills are made up of more than just energy prices. In fact, for Maine electricity customers, while the cost of Energy supply (in green) has fallen by more than 20% in the last decade, the total price for electricity (per kwhr) has actually crept up since a low of 14.2 cents/kwhr in 2015.

Table 3 – CMP Total Price by Component



As you can see from the chart above, the fastest growing portions of the retail electricity costs are charges related to Transmission and Distribution and those costs now account for more than half of the typical customer's electric bill. Though billed to most residential and small commercial customers on a per kwhr basis and to larger commercial customers based on their non-coincident peak loads, much of this increasing cost is not actually driven by either the overall energy consumption or the customer peak, but rather by *system* coincident peak loads. Because customers expect reliable electric service in all hours of the year, the whole energy system (both generation and transmission and distribution) are sized to meet those coincident peaks. The chart below, from MA DPU's recent 'State of Charge' report illustrates the outsized cost of building the system to meet these very infrequent peaks.

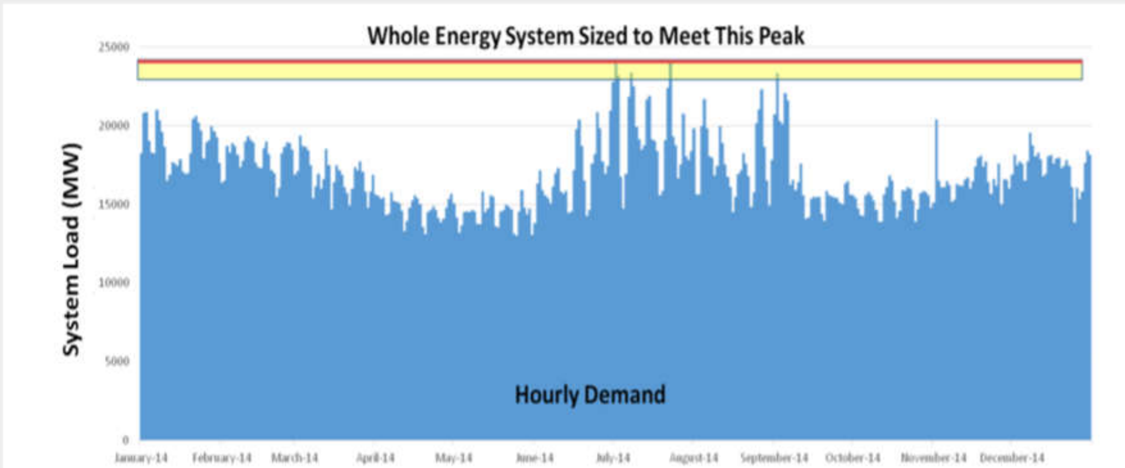
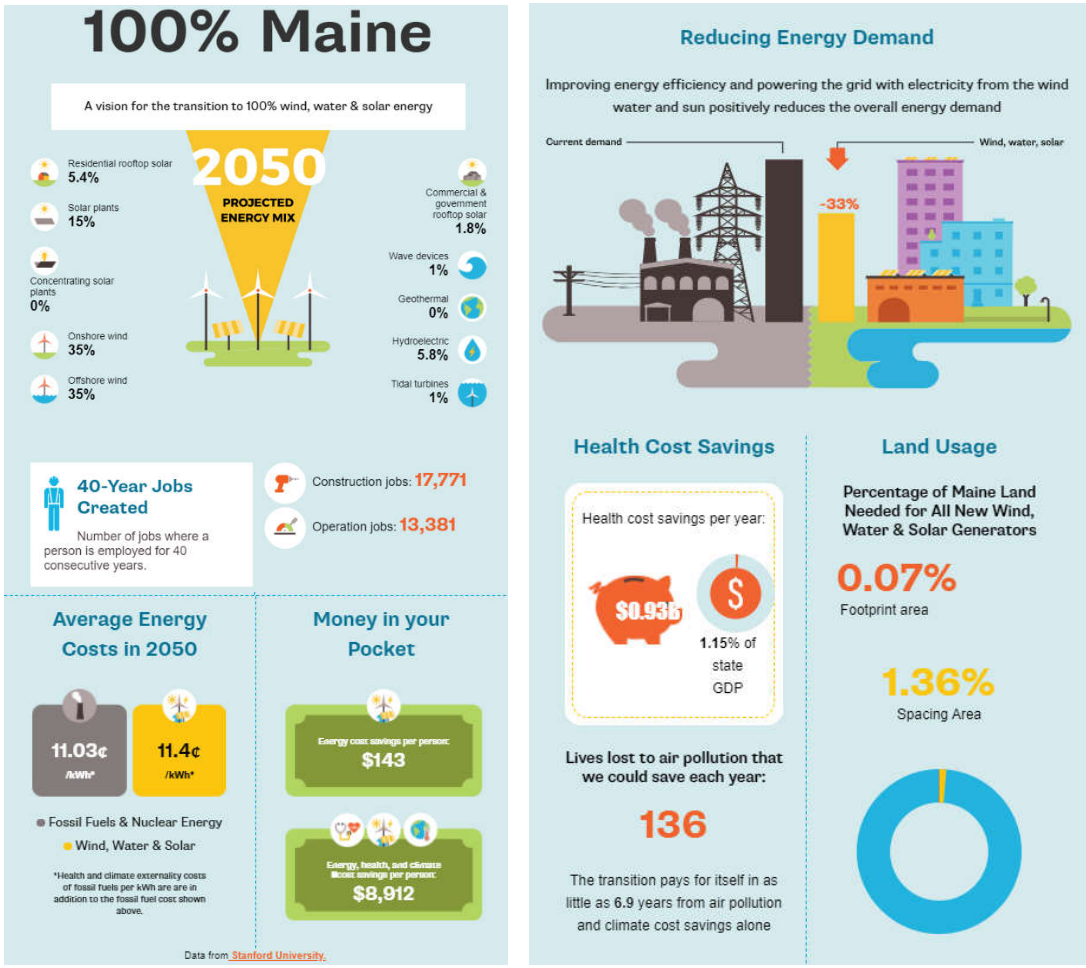


Figure 2: The whole electricity system is sized to meet peak demand

In that report, the authors calculate that when considering both Generation (supply) and Delivery (Transmission and Distribution), 1% of the hours of the year account for 8% of the overall system costs for MA ratepayers. And just 10% of the hours in the year account for 40% of the overall system costs. Though the details may vary slightly in Maine, there is no reason to believe the underlying dynamic is any different.

Electrical peaks are expensive for today's customers, and there is reason to believe they will be even more important in the future. The electric grid is at the beginning of its most significant transition since widespread electrification in the early 20th century. Widespread, if belated, recognition of the devastating consequences of burning fossil fuels on our natural environment have led policy makers from around the world and around the country to commit to 100% renewable energy targets. In some cases those targets seek just to produce 100% of current electricity use from renewable or non-polluting sources, but in recent years most policy makers have understood those targets to be insufficient and so increasingly Cities, Towns, States and Countries are committing to provide 100% of ALL energy from renewable sources, including end use energy that is currently provided directly by fossil fuels. There is a growing consensus that the most cost-effective and technologically practical way to achieve economy-wide carbon reduction targets is through a process known as Beneficial Electrification: replacing direct fossil fuel use with electricity and then making that electricity from renewable sources.

A recent study by Dr. Richard Silkman suggests that Maine could employ Beneficial Electrification to transition to a zero carbon economy by 2050, and do so at a cost that is lower than the status quo. Dr. Silkman's findings support similar findings by Prof Mark Jacobson at Stanford university whose team has conducted an individual analysis for every state in the US and found that in transitioning to 100% renewable energy by 2050, Maine could save an average of $143 per person per year on energy alone (or $8,912 per person per year when health and climate costs are also included):



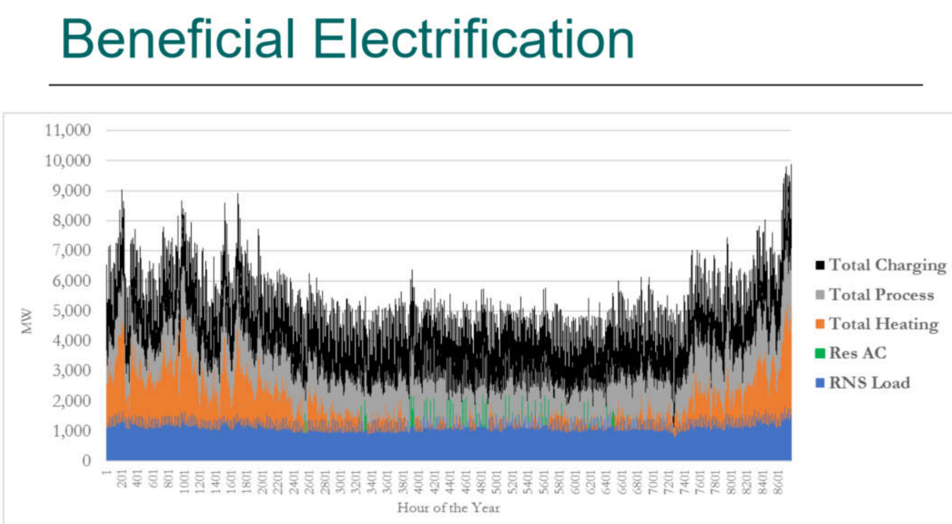
Though the economic and environmental benefits of this clean energy transition are compelling and clear, it will impose substantial challenges for the current electric grid. Dr Silkman estimates that while a fully electrified economy will increase total loads by a factor of 3x (12,048 GWh to 40,280 GWh), it will also increase the maximum peak demand by a factor of 5 (1,961 MW to 9,892 MW). That suggests that the importance of managing peak loads will only increase over the coming three decades.

Continued on next page

TABLE 2-3 | Summary – Electricity Use by End-Use Sector Under Beneficial Electrification

LOAD TYPE	TOTAL LOADS (GWh)	MAXIMUM DEMAND (MW)	MINIMUM DEMAND (MW)	AVERAGE DEMAND (MW)	CAPACITY FACTOR (%)
Current Use (RNS)	12,048	1,961	789	1,375	70.10%
Total Heating	7,453	4,954	0	851	17.20%
Residential AC	598	714	0	68	9.50%
Total Process	11,910	2,512	135	1,360	54.10%
Total EV Charging	8,272	2,486	102	944	38.00%
Passenger Vehicles	4,177	1,125	102	477	42.40%
Buses	340	233	0	39	16.70%
Trucks	3,755	1,622	0	429	26.40%
TOTAL LOADS	**40,280**	**9,893**	**1,449**	**4,598**	**46.50%**

Dr. Silkman's analysis also shows that those future peaks will likely occur at different times from our current peaks mostly due to the electrification of space heating. In the chart below, the current Maine RNS load is shown in Blue and peaks in Summer. But the expected, fully electrified load instead peaks in winter, driven largely by the heavily seasonal 'total heating' line, shown in orange. This indicates that the future will not only require an even sharper focus on peak load reduction, but also the flexibility to respond to the changing nature and timing of those peaks through the transition. Sophisticated controls and IOT tech are the solution.



Demand dexterity vs Demand response

Historically, grid operators have managed peak demand in one of two ways. They either build additional generation capacity along with T&D infrastructure to meet the peaks, or they design programs and incentives to call on very large industrial electricity consumers to curtail their consumption at the time of those peaks. The demand side programs are typically known as 'Demand Response' or DR programs. The confluence of widespread broadband internet and the proliferation of 'smart devices' provide an opportunity for a third way. Instead of picking up the telephone and calling a handful of large industrial power consumers and asking them to reduce consumption, grid operators now have the option to send an automatic signal to millions of distributed devices to accomplish the same goal, ideally in a more flexible and lower cost way. To differentiate it from traditional DR, we call this 'load shaping/flexibility' or 'demand dexterity'.

The grid of the 21st century will be digital, distributed and decarbonized, which creates new possibilities for demand side control. In addition to large Demand Response programs, grid operators can now call on load flexibility programs to shape electricity demand and lower costs. The illustration below shows how the flexible loads in a single home can be controlled to maximize solar self-consumption, and how a residential scale battery can add additional flexibility to provide a buffer for those loads that are not fully controllable.

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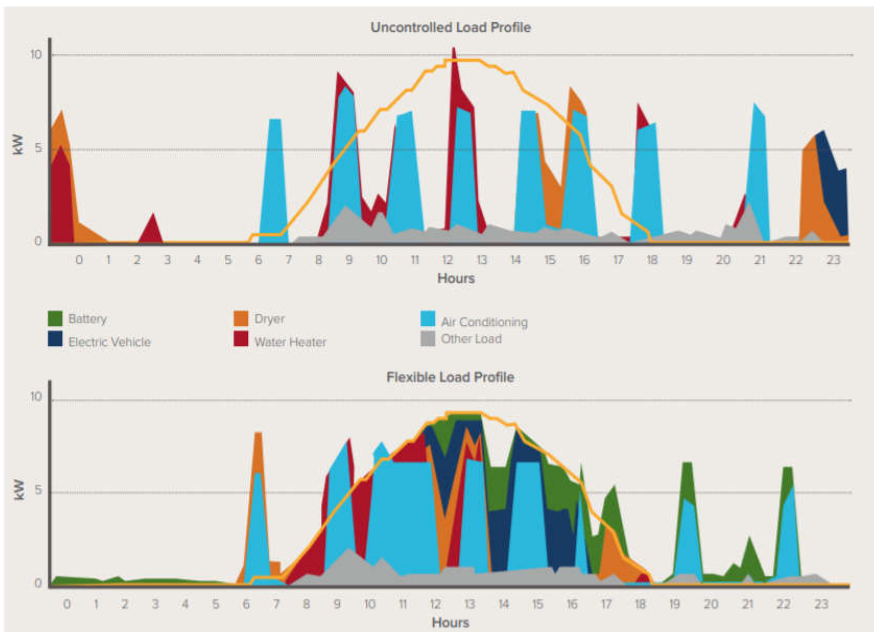


In this pilot, rather than optimize for a single home, we attempt to optimize for the grid. The future of the utility grid is distributed, bi-directional and transactive. Maine needs to create the blueprints for its grid modernization strategy and this Aggregated Distributed Energy Resources (DER) Pilot is intended as a demonstration project to begin accumulating data and experience to that end.

Proposal:

In the pilot project, Revision Energy Inc. (ReVision) and Virtual Peaker (VP) proposed to explore and demonstrate the value of demand dexterity by operating a fleet of at least 50 and up to 100 dispatchable Smart DERs for a one-year pilot. The DER fleet was primarily targeted to residential and small commercial customers and included four different kind of clean technology devices: air source heat pumps (mini splits), heat pump water heaters, electric vehicle chargers and residential battery storage systems.

In exchange for a rebate offered by ReVision Energy and funded by the EM pilot project, the customers agreed to allow ReVision and Virtual Peaker to take remote control of the devices up to a few times each month for the period of a year to try to shift loads and shape demand. The customer agreed to maintain internet connectivity for the devices with a minimum 95% uptime and 2 Mbps or faster speed for the year and to provide ReVision the necessary physical and digital access to control the device remotely. The types and frequency of load interventions were specified in a contract addendum ('Load Management Innovation Pilot Project Addendum) between ReVision and the customer:

- Heat Pump Water Heater: force the water heater on or hold the water heater off for no more than 6 hours in any given day and no more than 40 hours per week through the term of the Pilot. Contractor will make every effort to minimize the impact on availability of hot water for the customer.
- Air Source Heat Pump: change the heating or cooling set-point by up to 4 degrees Fahrenheit for no more than 6 hours in any given day and no more than 40 hours per week, through the test period.
- Energy Storage System: Charge or discharge the battery up to 4 times per week, not to exceed 10 times per month and never below 50% charge status.
- Smart EV Chargers: Control or throttle EV charging rate for up to 4 hours per day, not to exceed 40 hours per week through the test period.

In addition, the contract addendum specified that each customer should be notified in advance of any control intervention and have the opportunity to 'opt out' of the event, however the contract also limited the frequency of 'opt outs' to ensure that customers benefitting from the rebate actually participated in the pilot as expected.

Each device was installed at a customer's home and set up as usual for the customer's local and/or remote control. Then, in addition, the devices were interconnected with Virtual Peaker's central operations and control platform. Virtual Peaker does this by connecting its platform to the individual device's native control platform via a third-party API web integration. This means that the individual devices still only have a single connection inside the home, but that data is shared between the manufacturer's native app and server and Virtual Peaker behind the scenes.

Once all the devices were installed and connected, ReVision executed a series of load shaping interventions between July 2019 and June 2020. The testing program targeted different objectives in each month to simulate a variety of possible future use cases for third party remote control of distributed energy resources including : responding to time of use pricing, real time pricing, discrete dispatch events from an NTA Coordinator, (simulated) wholesale regional markets, and an environmental dispatch.

ReVision has provided Efficiency Maine with monthly reports over the course of the 12 month testing period detailing the testing protocols and findings of each individual test. This final report summarizes the high-level findings and takeaways from that testing and the pilot project. It will reflect on lessons learned from the experience and attempt to quantify the benefits that may accrue to both the participants (customer energy savings and cost reductions) and to ratepayers as a whole (including an evaluation of the potential for Aggregated DER fleets to contribute to energy and capacity price reductions, non-transmission alternatives to grid reliability needs, and reduced long-term grid infrastructure investments).

Objectives:

The goal of the pilot project was to demonstrate the ability of DERs to participate in and respond to time of use pricing, real time pricing, discrete dispatch events from an NTA Coordinator, and (simulated) wholesale regional markets. In addition to demonstrating the value of this load flexibility for both participating and non-participating ratepayers, the pilot sought specifically to understand customers' willingness to participate and to generate practical hands-on experience for Efficiency Maine to inform possible future program design.

Key questions and objectives of the pilot are listed below:

- Will customers allow third party control of BTM devices in exchange for modest up-front incentive?
- Test effectiveness of and build experience with a communications and control platform. Understand the pros and cons of relying on customer internet for connectivity.
- Quantify how effective different device types are in load shifting for various applications.
- Understand customer satisfaction/tolerance with third party control.
- Generate local Contractor experience with hardware and devices.

These questions and objectives are answered below.

The Platform:

As interest in control of distributed energy resources increases, there are a number of companies providing third party remote control of these devices. In sufficient numbers, these devices can be aggregated and function as a 'virtual power plant' providing many or all of the services that are historically provided by a conventional utility generator.

To date, much of the aggregation of individual devices has been done either by an individual product manufacturer or developer. For example, Tesla, a supplier of residential and utility scale batteries, has developed a software platform they call 'Opticaster' which they use to interface with utility programs around the country and control batteries which they own, as well as some on behalf of third party owners for a variety of grid management objectives. Sunrun, a national solar developer but not a manufacturer, also operates a similar platform which they use to control a battery fleet including batteries manufactured by a number of different vendors and installed by their channel partners. Chargepoint and Enel-X are doing something similar with their fleets of EV chargers, which in most cases they manage but don't install or own.

In addition to device manufacturers, as more utilities and other grid operators recognize the importance and the value of this control in evaluating long term investments, a new stable of software platforms is beginning to emerge. These platforms, known as Distributed Energy Resource Management Systems (DERMS) are enterprise scale software that can help utilities or grid operators manage DER programs from end to end, including modeling, planning, and interconnection, as well as operations, billing and maintenance. Examples of enterprise scale DERMs are software from AutoGrid and Siemens, among others:

Source: Green tech media

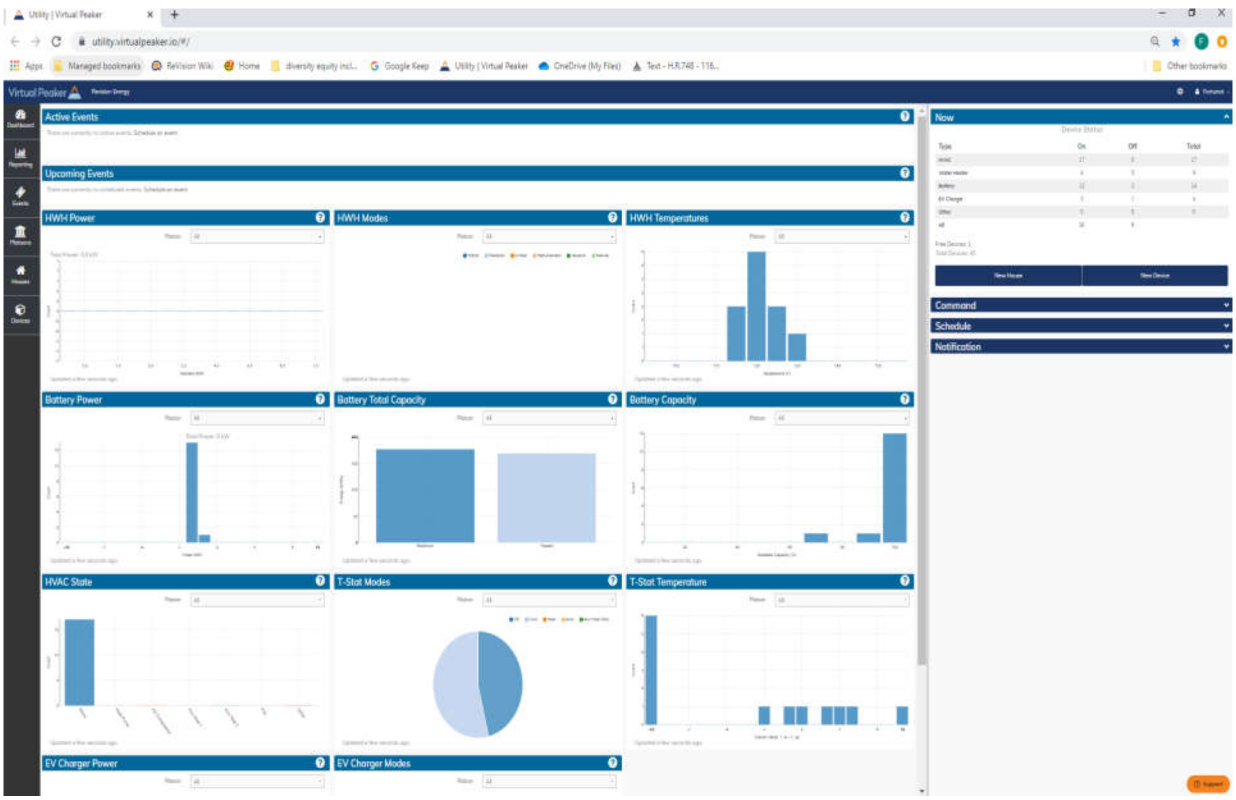
For this limited scale pilot, we did not require an enterprise level DERM software tool, but rather just a platform that allows for efficient third party control of a variety of different devices. The partner we selected for this effort is a company headquartered in Louisville, KY called 'Virtual Peaker.' Virtual Peaker is a software-as-a-service (SaaS) platform designed to connect residential smart devices for utility or third-party control. The platform integrates with thermostats, water heaters, EV chargers, residential battery systems, mini-split heat pumps and room air conditioners to shift load, save energy and help utilities better understand their customers. Connectivity is established using the Internet of Things (IoT), supported by native WiFi connections of existing consumer-grade hardware. This means that web-enabled customers do not need additional devices in the home to interact with the utility. This also makes the platform infinitely scalable with a limitless number of devices and device types.

Virtual Peaker bills themselves as a sort of 'univeral translator' which can take a control signal and translate it (via API connection) to smart devices of a variety of different types and from a variety of different manufacturers. This ability to manage mutiple device types and manufacturers in a single platform and without requiring dedicated IT investment was important for our small pilot, as it is to many of their utility customers who tend to be vertically integrated utilities in regulated markets, or smaller municipal utilities who provide both default energy supply and T and D to their customers. Examples of VP's current clients include: Green Mountain Power (VT), Vermont Electric Coop, Belmont light (MA), Glasgow Electric Plant board (KY), Sacramento utility district (CA) and the Washington Electric Coop (WA).

The VP approach relies on the native wifi or internet connectivity of smart home devices. Once a DER device is installed by ReVision's team of electrician, plumbers and HVAC technicians, that device is connected to the internet via its native app. For example, as part of our normal commissioning of a Ruud smart heat pump water heater, we connected the water heater to the customer's local area network (typically via wifi, but sometimes also hard wired), and then set the customer up with the Ruud homeowner 'app' to control the water heater and/or receive alerts. For the customers participating in the pilot, there was one additional step which was to ask them to activate their account in the Virtual Peaker platform and to approve the connection between the platform and the device's native server. So in the example of the water heater, VP does not communicate with the water heater itself, but with the Ruud server, which is in turn communicating with the water heater. Once that connection has been established and the third party control permission granted, the Virtual Peaker platform can send control signals to the server (and on to the device), just the same as the homeowner can do with their device specific app.

This architecture requires that Virtual Peaker develop a customized 'integration' with the server of any device type we want to control. VP had a series of existing integrations which we took advantage of, but we also had them create a new one with Pika (now generac).

Once the devices were all loaded into the platform, VP provided ReVision with a single access point to monitor and control all the devices. The platform allows us to program specific interventions or 'events' either for individual devices, for 'platoons' of devices or for the entire fleet. When such an event is programmed, the platform sends a notification to the end customers and allows them to opt out. It then sends the control signal to the devices and collects data in (near) real time for analyzing the effect of the 'event'. The Virtual Peaker platform includes a number of features and functionality which were not used in this pilot, but which can enhance control and data analytics. Below is a screen shot of the VP dashboard:



<u>Installation and connection experience</u>

Installation of the devices was generally straightforward and seamless. ReVision has nearly two decades of experience installing thousands of clean energy projects for residential customers and these pilot projects were generally unexceptional in that regard. As described above, the only additional steps required for pilot project participants was to walk the customer through the process of connecting their new device to the Virtual Peaker platform. ReVision's installation project manager typically helped customers through this step at the completion of an installation, though the process is really designed to be 'self-service' and could certainly be accomplished by the individual customer on their own 90% of the time:

-ReVision creates an account ('Home') in the VP platform for the customer.

-The customer receives an e-mail from Virtual Peaker asking them to log into their account.

-They then select 'add a device' and when queried for the device type they select from a list

-Then the customer is asked to enter the user name and password that they used with the device's native interface (for example on the Rudd water heater app).

-With this information, VP automatically connects that customer's VP 'Home' with the device information associated with that log in information.

In general, this process worked smoothly for most customers. A small fraction of the overall projects were installed in new homes or newly renovated homes where either the customer/homeowner is not yet present or internet connectivity/wifi doesn't exist yet. Those projects required either a return trip to commission the VP interface, or some additional remote help and troubleshooting from the ReVision team once the customer fully moved in.

Testing highlights and Insights

Once the DER fleet (total of 44 devices) was fully installed and commissioned, we spent the months of July 2019 through June 2020 simulating a variety of load conditions that would justify calling a 'load shaping event' for the fleet. Those use cases included reducing consumption at the time of the annual generation peak (Capacity peak which sets iCap tag) in July, Aug and June. In the fall and winter months, we simulated a handful of different TOU rate schedules to reflect the differences in cost of generation at different times of day and attempted to also respond to monthly peaks (RNS peaks) which are used to allocate shared regional Transmission costs to different ratepayers and states. Finally, in the month of May 2020, we employed an 'environmental dispatch' strategy, optimizing the distributed load not for lowest cost, but for lowest carbon impact. Another use case which was not specifically simulated but can be extrapolated from any one of the monthly tests is the use of distributed resources as a 'non-wires alternative' or NWA. NWA's, sometimes also called Non Transmission Alternatives (NTAs), are any resource or combination of resources that can replace or delay the need for additional transmission or other conventional utility infrastructure investment. NWA's are typically identified using typical utility planning scenarios, and while in some cases they require very long term (full day or multi-day) time periods, there are also many cases where a relatively short duration (3-4 hour) load shaping is meaningful and in those cases a fleet of DER's such as the one in this pilot project may be very compelling.

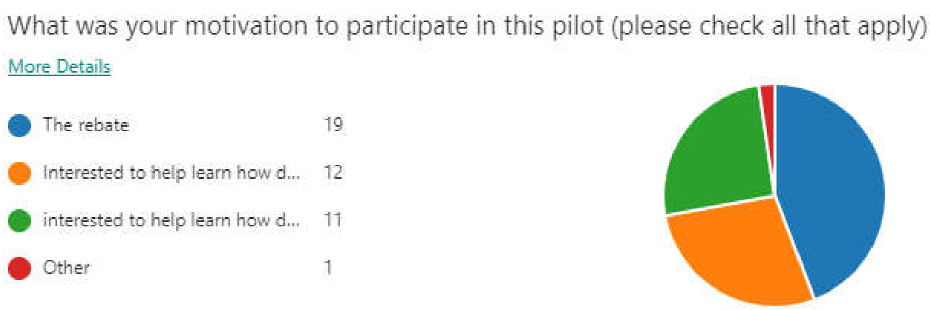
While individual device and fleet performance varied by month and by the particulars of the load intervention that we chose to match with a particular use case, some significant results were fairly consistent across the test year. Individually monthly test protocols and results are included in the monthly reports, but there are also some common high-level takeaways from the program overall, as follows:

1- Value of flexibility varies by season and by device type

- Air Source Heat Pumps are not yet very useful as summertime load management in Maine because not that many of them (<25%) are consistently used in cooling mode. The mini splits heat pumps that were operating proved to be fairly responsive to call for load shedding, but because the heat pumps are very efficient, the actual load shifted per device is small (a few hundred watt hours per responding device).
- Heat Pump water heaters are relatively easy to control with minimal impact on customers. As with mini splits, HPWH's are very efficient in heat pump mode and so the shifted load per device is also relatively small (few hundred watts hours per responding device). Care is necessary when coming out of a setback condition to avoid accidentally using the resistive backup heater rather than the heat pump to recover the tank.
- Batteries are the most expensive of the devices in our fleet but also far and away the largest and most flexibly controllable devices overall. With a few exceptions, battery availability is not dependent on customer behavior and so the batteries tend to always be available when called upon. Batteries can also shift a significant load, as much as 5 kW peak and up to 10,000 watt hours. As a result of their high power and high availability, a single battery system is as effective at load shifting as roughly 30 to 40 air source heat pumps combined.
- EV Chargers are also a very significant load, but unlike battery systems, their availability was very low. This is particularly true of residential chargers which tend to have a relatively low duty cycle and even lower peak coincidence. EV chargers are certainly worth controlling because they represent such a significant load both for an individual household and for a future fully electrified economy. A charger program that includes both residential and commercial/workplace charging would likely have a more diverse load pattern and thus higher demand flexibility value.

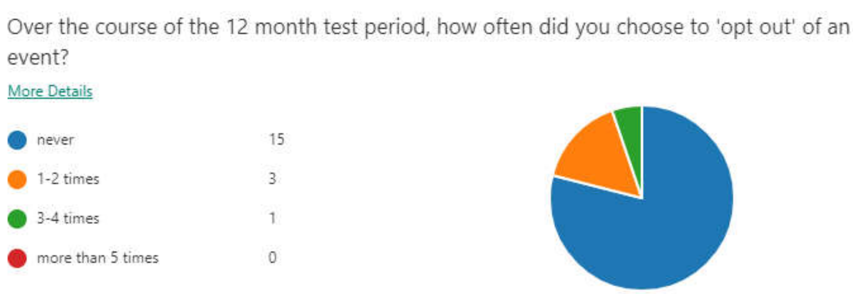
2 -Customer motivation varied but was not purely financial. While 100% of customers who responded to our post project survey (19 of 19) indicated that the financial rebate was part of their motivation to participate in the Pilot, a majority also reported that they were motivated by:

> "Interested to help learn how distributed energy resources can lower costs for all ratepayers" = 12 of 19
>
> "Interested to help learn how distributed energy resources can help integrate higher levels of renewables on the grid" = 11 of 19



This is a useful takeaway to help inform marketing decisions should Efficiency Maine pursue similar programs in the future.

3- Customer acceptance was good overall and opt out rates were low throughout the test period. The data from the VP portal and self-reported 'opt out' rates for the program were low throughout the year, with most customers never opting out of an event at all.



For those customers that did opt out, the reasons provided ranged from a desire to maintain control over the device at that particular time, to confusion or customer error. Only a single respondent indicated that one time they "opted out part-way through as the home was becoming uncomfortable" (hot, humid day). But in general, when asked whether the control interventions affected them, most indicated that they either didn't notice the events at all (14 of 19) or that they noticed the events but were never uncomfortable (3 of 19).

Other than text or e mail notifications, did you ever notice that an event was in progress?

More Details

Only two respondents noticed an impact on comfort at all through the year, including the one who opted out midway through an event because of room temperature and one other who misunderstood the battery programming and was concerned that we'd leave them with a fully drained system at the end of an event.

Overall, customers indicated a strong interest/willingness to participate in a similar program in the future:

If offered an opportunity in the future to enroll a device (water heater, heat pump, battery, EV charger) in a smart grid program in exchange for monetary compensation, how likely are you do to do so? (1= Definitely not ... 5= Definitely would participate)

More Details

19	4.26
Responses	Average Number

4- Communications relying on customer internet is generally viable, if imperfect. One of the most substantial challenges of controlling a fleet of distributed energy resources is maintaining consistent communication with all devices. While some DER control programs rely on a dedicated communication channel (typically either cellular, utility power line communication or utility AMI systems), most depend on the customer's local network and internet connectivity. While relatively inexpensive, this comes with some challenges as customer internet quality varies widely, as does their technical sophistication if asked to troubleshoot or correct communication challenges.
It is worth noting that Connectivity/Bandwidth to the customer's home was almost never an issue; virtually all device communication challenges occurred either on the customer side (local area network issues), or at the manufacturer server (stability of device connections and consistency of API connection to Virtual Peaker). The latter of these will naturally improve as hardware and software matures and as programs scale. The former will continue to be a challenge, though a few key lessons learned for future programs include:

-Though more costly up front, providing a hard wired connection to the local area network rather than relying on a wifi network is more reliable and consistent. Wifi network names change, passwords are updated, etc while hard wired connections stay consistent.

-One substantial benefit of controlling devices via API connection to the native device control app server is that because the customer is presumably also using the app for control, they are likely to identify and be motivated to repair connectivity issues.

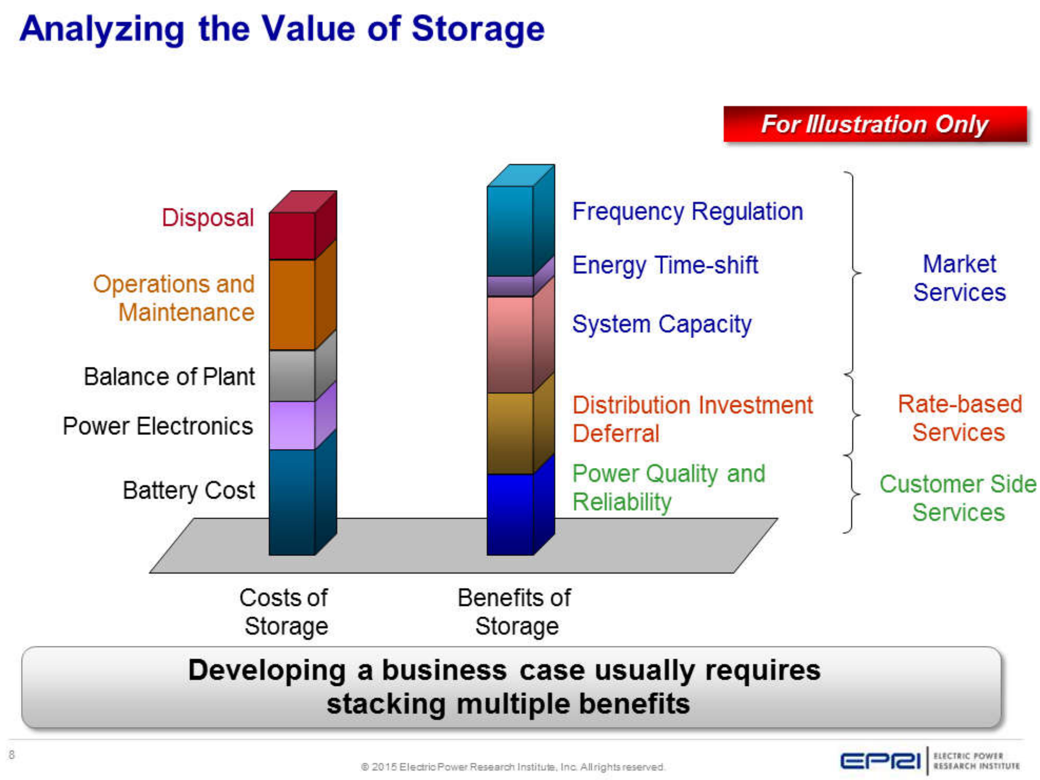
-it is important for fleet operators to continually troubleshoot connectivity issues with devices, so they do not just crop up during high value/high performance risk events. With this small pilot, this oversight could be done manually, but in larger programs that oversight needs to be automated. This is particularly important for programs which expect to derive substantial revenue/savings from low occurrence and high value markets such as the Capacity market, where just a single hour or two drive financial performance for the entire year.

-Programs that pay for performance, either based on performance during discrete events, or in aggregate as in this program (with part of the rebate reserved for payment at the end of the program), help to provide incentives for customers to keep devices connected.

Calculating financial benefits:

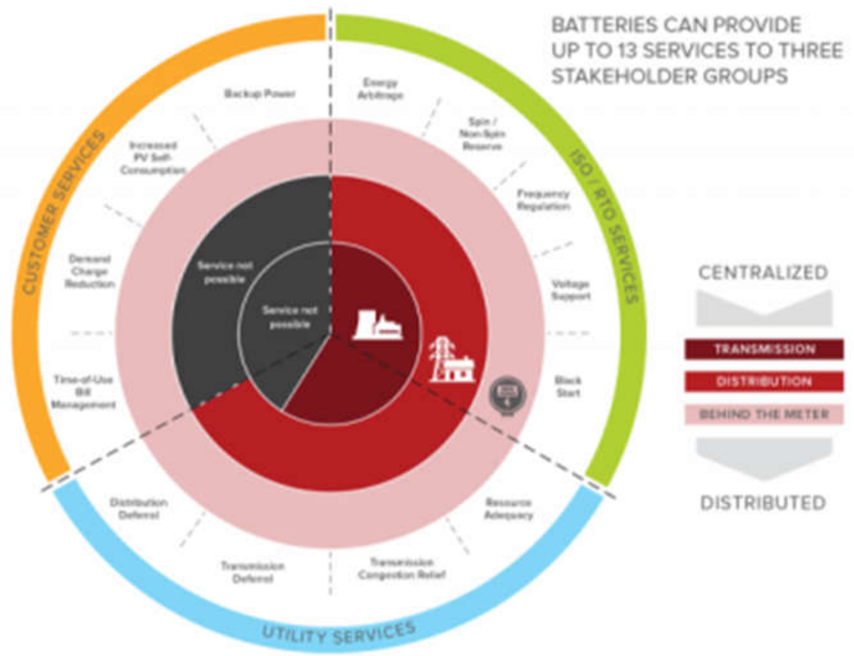
While there is widespread agreement that load flexibility brings value to the grid, one of the more challenging aspects of creating sound policy and programs for the aggregation and control of distributed energy resources is to arrive at an accurate measure of value for each of the multiple value streams that distributed resources can provide, both to the individual customer and to the grid as a whole. This analysis is critical for developing programs where ratepayer or other public dollars are invested to incentivize the installation of DERs, as well as their aggregated control. Efficiency Maine has ample experience and expertise in performing cost/benefit analyses for the types of devices employed in this pilot generally, so our analysis focuses on any *additional* value that may be created by the *control* of those devices, rather than the devices themselves. For example, replacing an electric water heater with a heat pump water heater reduces both device total and peak loads. Adding smart control to that heat pump water heater won't further reduce device loads but may reduce or eliminate that device's contribution to peak grid load or costs in other ways.

Because the cost to deploy and the to control a fleet of these devices is not trivial, in many cases a single use case or ratepayer value proposition is insufficient on its own to justify the public investment required. However, when multiple value stream or use cases are combined the outcome is sometimes different. This concept is often referred to as 'value stacking' and is a critical part of understanding the cost-benefit of these programs.



For example, a solar + storage system may be able to create value/benefit for ratepayers by reducing house load to zero (or even negative) at the time of the annual capacity generation peak. Reducing consumption at that peak time, reduces the Icap tag obligation of Maine residential ratepayers as a whole and thus saves all ratepayers money in the near term, and reduces the need to build new power plants and thus lowers ratepayer costs as a whole over the long term. But as previously explored, that use case really only requires the battery to be available for a few hours in late afternoon on a handful of days in July and August. There may be an opportunity in the remaining 8700+ hours of the year for the battery to provide additional ratepayer benefit, which can help improve its overall cost effectiveness. For example, the battery can also target monthly RNS peaks, which reduce Maine's share of regionally shared Transmission network costs. The battery may also charge/discharge daily based on the spot market price of electricity, thus helping to reduce demand in expensive hours and increase demand in cheap hours and thus reduce the overall costs of energy supply for all customers. If deployed in a more geographically targeted way, the battery may also help to defer or eliminate transmission or distribution investment and thus reduce costs for ratepayers that way. By combining those discrete values provided by control of a single device, a program which may not be cost effective based on a single value steam, may actually make sense.

Finally, it is important to remember that one of the most powerful benefits of siting these DER's behind a customer meter is that all of those stacked ratepayer values are themselves stacked on TOP of whatever value the device provides to the customer; in the case of a battery storage system primarily resiliency and possibly customer demand charge or TOU management. In their 2015 report on the Economics of Battery Energy Storage, the Rocky Mountain institute identified 13 distinct services or value streams that a customer sited battery can provide. Four of those thirteen accrue to the benefit of the individual customer (shown in orange below), but the balance accrue to ratepayers generally (shown in green and blue in the illustration below):



When installed behind a customer meter, in most cases, the ‘customer services’ provide enough value to the customer that they are willing to invest their own private capital to pay for the vast majority of the investment. In those cases, it is far easier for the remaining nine ‘ratepayer’ services/values to be cost effective with respect to whatever public ratepayer investment may be required. This combination of private (customer) value and public (ratepayer or environmental) value also illustrates why some of the historically favored utility cost effectiveness tests, such as the Total Resource Cost test, are not a good way to evaluate customer sited and customer owned DER programs. Those tests have generally been constructed to evaluate monopoly utility investment in which the total investment costs are borne by ratepayers generally, and therefore the whole cost of investment must be offset by ratepayer benefits. For customer owned, behind the meter investments, the math is somewhat different and other tests such as the Ratepayer Impact Measure or Societal Cost test may be more appropriate.

Though the above examples are focused on energy storage, almost all of the same value stacking opportunities exists with any controlled, behind the meter DER including water heaters, heat pumps/smart thermostats, and electric vehicle chargers (the exception being perhaps some of the ISO/RTO services such as Voltage support or Frequency regulation, which batteries can do, but water heaters or EV chargers generally can’t).

One challenge in analyzing these values is that retail markets do not exist for many or most of the nine services identified above. In many cases we therefore must approximate the ratepayer value from the equivalent centralized wholesale market and then attempt to make adjustments to reflect any additional value that is a function of the distributed nature of the DER solution.

This is similar to the process used in many of the 'value of distributed solar' studies undertaken around the country in recent years, including here in Maine in 2015, as well as in the annual Avoided Energy Supply Components (AESC) in New England report, published annually by Synapse Energy Economics. The Synapse study is rigorous and widely used by efficiency program administrators and so rather than attempt to recreate the analysis of value for individual components, we have attempted to use the values from the 2018 AESC where possible.

Capacity Peak Value

Most DER pilots focus primarily on capturing the value of reduced generation capacity costs. This is because Capacity is traditionally the second largest portion of a customer's energy supply bill and is relatively easy to target because the capacity peak has been fairly predictable in New England for many years.

The clearing price of the Forward Capacity Auctions run by ISO new England has varied considerably over the last few years, in part because of changes in the generation fleet and in part because of changes made by the ISO in how they conduct those auctions. This volatility has made it difficult to predict the future value of the Capacity of controllable loads and even the AESC has had to make substantial revisions to previous estimates to reflect the changing market. In the 2018 report, the authors calculate that "a load reduction in the summer of 2018 is worth 12 times the 2018/2019 clearing price, or $118/kW, spread over that period." Looking forward 15 years, AESC develops a levelized estimate which is $6.42/kw/mo (or $77.04/kw per year). The table below uses this lower, levelized cost and reflects the Capacity reduction and value by device type:

	A	B	C	D	E	F
1	Device	peak W per available device	% operating	15 year levelized Capacity value ($/kw/mo)	15 year Capacity value of single available smart device (NPV)	15 year Capacity value of all devices (NPV)
2	Heat Pump Water heater	400	20%	$77.04	$369.79	$73.96
3	Air Source heat Pump	350	25%	$77.04	$323.57	$80.89
4	EV Charger	7000	25%	$77.04	$6,471.36	$1,617.84
5	Battery Storage	5000	100%	$77.04	$4,622.40	$4,622.40

Note that the average value of the device (column F) is impacted substantially by the fraction of the devices that are operating or available concurrent with the peak (column C). The estimates of available/operating devices in the table is based on our aggregate experience in this pilot project but given the significant impact on actual value these estimates warrant additional investigation.

Capacity DRIPE

When a demand side resource, such as the DER fleet, successfully targets the capacity peak and thus reduces the capacity demand, that reduction not only eliminates the direct demand but reduces the cost of all remaining capacity as well. This effect is known as Demand Reduction Induced Price Effect or DRIPE, which refers to the reduction in prices in the wholesale markets resulting from the reduction in demand in those markets due to the impact of efficiency and/or demand response programs. DRIPE affects both wholesale energy and capacity markets though for this analysis we include only Capacity DRIPE. As with capacity value, we use the 2018 AESC report to develop a reasonable estimate for value of Capacity DRIPE for each device type. The AESC calculates the value of Capacity DRIPE for both resources that are bid into the FCM and for unbid resources. Interestingly, the report finds that "Capacity DRIPE for un-bid resources is approximately two times higher than that of bid capacity DRIPE, but benefits accrue many years later. We find that un-bid DRIPE is worth more than bid DRIPE due to changes in capacity market fundamentals and different DRIPE effect timeframe." Consistent with the analysis in that report, we utilize a 10 year levelized number rather than a 15 year one to reflect the short time duration of DRIPE impacts.

The 10 year levelized Value of Capacity DRIPE for resources not bid into the FCM by AESC is $311.01 per kw/year. The table below uses this levelized cost and reflects this Capacity DRIPE value by device type:

Capacity Dripe

Device	peak W per available device	% operating	10 year levelized Capacity value ($/kw/yr)	10 year Capacity value of single available smart device (NPV)	10 year Capacity value of all devices (NPV)
Heat Pump Water heater	400	20%	$311.01	$124.40	$24.88
Air Source heat Pump	350	25%	$311.01	$108.85	$27.21
EV Charger	7000	25%	$311.01	$2,177.07	$544.27
Battery Storage	5000	100%	$311.01	$1,555.05	$1,555.05

Note: As a function of the way in which ISO NE ratepayers share costs, ME ratepayers actually realize only about 8% of this total, with the balance being savings to other New England ratepayers in proportion to their peak capacity payment obligations. For the sake of this analysis we felt it was appropriate to use the region wide ratepayer savings whether they accrue inside or outside the state.

Transmission cost savings (RNS Savings)

In addition to reducing the required generation capacity, shaping load to reduce peaks also has an effect on the cost of transporting that electricity from generators to consumers. Those costs include both the shared regional transmission investment (Pool transmission facilities), as well as the local transmission and distribution costs. Per ISO new England, Pool Transmission Facilities (PTF) "are those facilities owned by participating transmission owners that meet the criteria specified in the Open Access Transmission Tariff and over which the ISO has operating authority. Generally, PTFs are those rated 69 kV or above required to allow energy from significant power sources to move freely on New England's transmission system." The use of those PTF to move electricity within the new England region is known as the Regional Network Service or RNS. Though the cost of the RNS is shared by New England customers according to their Monthly Regional Network load value, or in other words, based on their load at the time of the monthly peak, the AESC report suggests that the PTF cost savings estimates should be "applied to the reduction in summer peak load, which appears to dominate ISO New England's transmission planning." AESC 2018 calculates an avoided cost for Pool Transmission Facilities

(PTF) of $94/kW per year in 2018 dollars, which is the same number we use here.

RNS Savings					
Device	peak W per available device	% operating	10 year levelized RNS savings value ($/kw-yr)	10 year RNS savings value of single available smart device (NPV)	10 year RNS savings value of all devices (NPV)
Heat Pump Water heater	400	20%	$94.00	$37.60	$7.52
Air Source heat Pump	350	25%	$94.00	$32.90	$8.23
EV Charger	7000	25%	$94.00	$658.00	$164.50
Battery Storage	5000	100%	$94.00	$470.00	$470.00

Wholesale energy cost savings/ Energy arbitrage

In addition to lowering the absolute peaks which drive Capacity, DRIPE and Transmission savings, the fleet of DER's also proved its ability to shift loads across other hours of the day. Because wholesale energy costs vary substantially across the day, this load shaping presents an opportunity for additional ratepayer savings. If the participating customer/DER owner is enrolled in a time differentiated energy supply agreement, such as real time pricing or TOU, some of this ratepayer benefit may accrue directly to the customer themselves. But if the customer is not enrolled in a time differentiated rate (as most residential customers aren't) the benefits still exist, they just accrue to the electricity provider who now serves a customer whose load is cheaper to meet than an unmanaged load. If the customer is on default service and assuming the market to provide default energy supply is an efficient and competitive one, that should result in a reduced cost for all default service ratepayers over time.

The value of the savings from each device is a function of the energy shifted and the differential in cost of that energy between the original load timing and the controlled load timing. Using historical wholesale price data, it is theoretically possible to calculate the maximum value of that load shift assuming a control algorithm with perfect predictive analytics or perfect 20/20 hindsight. Such an analysis provides an upper bound for the value of energy shifting. Another alternative for calculating the value of energy shifting is to use the average seasonal difference between on peak and off peak electricity prices. Because averaging tends to smooth both the price peaks and valleys, this latter approach likely underestimates the potential value of load shifting and therefore provides a lower bound on that expected value. To be conservative in our analysis and for simplicity's sake, we use the latter method here.

For calculating the cost difference for on peak and off peak energy supply, we again rely on the 2018 AESC report, which details the seasonal on and off peak avoided retail energy costs by State (levelized over 15 years):

Table 45. Avoided retail energy costs, AESC 2018 vs. AESC 2015 (15-year levelized costs, 2018 $ / kWh)

			Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2018	1	Connecticut	$0.065	$0.060	$0.050	$0.044
	2	Massachusetts	$0.064	$0.059	$0.050	$0.044
	3	Maine	$0.059	$0.055	$0.046	$0.040
	4	New Hampshire	$0.065	$0.061	$0.052	$0.045
	5	Rhode Island	$0.063	$0.058	$0.049	$0.043
	6	Vermont	$0.064	$0.059	$0.050	$0.043

The winter price difference is $.004/kwhr. The summer price difference is $.006/kwhr. Combining our pilot testing data with some assumptions about unit availability throughout the year, we arrive at the following table of annual retail energy cost savings:

Energy Shifting					
Device	**daily load shift (kwhr)**	**% operating and available**	**Winter price differential ($/ kwhr)**	**Summer price differential ($/kwhr)**	**15 year Energy Shifting savings value of all devices (NPV)**
Heat Pump Water heater	1.2	90%	$0.004	$0.006	$29.16
Air Source heat Pump	1.2	50%	$0.004	$0.006	$16.20
EV Charger	21	50%	$0.004	$0.006	$283.50
Battery Storage	10	100%	$0.004	$0.006	$270.00

Non Wire Alternative Value

As previously described, Non-Wire (or Non Transmission) Alternatives are situations where grid edge devices can be developed and installed to eliminate a transmission or distribution planning reliability violation and can do so at a lower cost to ratepayers than a traditional poles and wires solution. When a particular local upgrade need is identified on a circuit, the value of a kW or kWhr of behind the meter, aggregated controlled DER in a particular location may be many times higher than the *average* value of Transmission avoidance per kW identified by the AESC report.

In contrast to system peaks that drive Capacity and bulk Transmission costs, the particular reliability violations that may trigger an NWA vary substantially in terms of their duration and their timing. In a recent report for the NH PUC studying the potential for DG renewable energy to defer distribution upgrades, Guidehouse energy consultants reported that while “most locations have capacity deficiencies during late afternoon or early evening hours, the number of hours of capacity deficiency varies significantly by location, with some locations with fewer than 15 hours of deficiency per year, while other locations are capacity deficient for several thousand hours per year.”

This heterogeneity in the need makes it difficult to estimate the value of DG or DER in this application in a generic way. In some cases, capacity deficiency is driven by peak load and so is relatively similar in duration and timing as the Generation Capacity peaks. In other cases, deficiencies are long duration violations for which a load shaping resource like the DER fleet is nearly useless.

While calculating the potential value of the DER fleet for individual NWA applications is obviously well beyond the scope of this pilot, we include some representative sample numbers here both from Efficiency Maine's Boothbay smart grid pilot and from the Guidhouse study in NH, because they illustrate how a possible extended pilot could target specific geographies for deployment or with additional incentive in order to capture this additional ratepayer value.

Boothbay eliminated a 2MW violation, which would have cost $18M. Simple math says that value is $450 per kw-year (20 year). No discount rate, but also no O and M or other utility costs included: "The economic value of capacity investment avoidance varies significantly among the 16 locations based on a theoretical analysis of capacity avoidance using the RECC approach. The maximum hourly economic value of capacity investment avoidance ranges from under $1 per kilowatt (kW) per hour to over $4,000 per kW per hour. The greatest driver for that variance is the total number of hours over which capacity deficiencies occur at a specific location. The lower value is generally indicative of a capacity deficiency that occurs over a large number of hours, while the higher value is generally indicative of a capacity deficiency that occurs during fewer hours." Dividing the Maximum $/kw/hr by total hours of deficiency, you see values of between 0 and $2,200 per kW-year.

Location	Year Considered	Revenue Requirement	Total Hours of Capacity Deficiency	Total Annual MWh of Capacity Deficiency	Maximum $/kW/hr	Relative $/kW/hr Value Ranking
Pemi Substation (Bulk)	2020	$9,074,650	326	509	$2.45	11
Portsmouth Substation (Bulk)	2020	$3,037,438	1,966	7,446	$0.04	16
South Milford Substation (Bulk)	2020	$15,976,924	6,696	41,928	$0.05	14
Monadnock Substation (Bulk)	2020	$17,374,146	15	10.53	$203.68	6
East Northwood Substation (Non-Bulk)	2021	$242,995	3	0.07	$256.77	5
Rye Substation (Non-Bulk)	2022	$3,644,926	2	0.10	$3,185.54	2
Bristol Substation (Non-Bulk)	2020	$1,457,970	5	0.43	$301.37	4
Madbury ROW Circuit (34.5 kV)	2020	$2,429,950	7	14	$17.03	8
North Keene Circuit (12.47 kV)	2028	$1,858,912	1	0.11	$1,128.25	3
Londonderry Circuit (34.5 kV)	2020	$747,210	467	115.81	$1.01	13
Vilas Bridge Substation (Non-Bulk)	2020	$2,715,803	909	247.68	$2.91	10
Mount Support Substation (Bulk)	2020	$7,557,017	1,329	21,484	$0.04	15
Golden Rock Substation (Bulk)	2020	$8,983,404	164	434	$3.14	9
Bow Bog Substation (Non-Bulk)	2026	$299,375	5	0.27	$128.17	7
Dow's Hill Substation (Bulk)	2022	$525,674	2	0.008	$4,483.12	1
Kingston Substation (Bulk)	2020	$14,371,184	203	789	$2.00	12

Though it is not possible to estimate a generic value by device for an NTA application given the huge spread of total savings and of application types, the magnitude of some of the possible values (on the order of $200-500/kw-yr) is pretty significant so that especially when stacked with other possible value streams, this could certainly help make many applications cost effective.

Carbon Reduction Value

Finally, though the cost effectiveness tests used by Efficiency Maine and other efficiency program providers typically do not explicitly value carbon reduction (except in so far as they are monetizable in an existing market), clearly this is a subject of great interest for policy makers in

Maine and elsewhere as we consider the best pathways towards a carbon neutral or carbon negative economy.

In our May 2020 test, we ignored market price signals and instead optimized dispatch of the fleet on environmental (carbon avoidance) basis. While ISO-NE does not publish a real time carbon intensity metric for the electricity it provides, there are a number of other proxies we can use in its place to provide a first order estimate for the ability of a controllable DER fleet to reduce carbon pollution. The numbers below should be understood as approximations, and furthermore it is clear that as generation mix in New England changes, these numbers are likely to change as well. But even without perfect resolution, we can understand that load flexibility provides substantial opportunities for carbon reduction.

The left hand chart below from an ISO NE CLG presentation, shows that shifting load just a few hours can reduce CO2 emissions per MWh by as much as 10-20%. The center and right chart show that pricing and/or system load is not a perfect proxy for carbon accounting.

Hourly Average Marginal Emission Rate ($lbs\ CO_2/MWh$)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12 AM	1,077	1,015	968	933	868	952	929	983	938	958	876	972
1 AM	1,059	1,039	1,004	925	881	940	877	964	937	952	892	981
2 AM	1,086	1,025	1,033	972	935	997	933	942	990	925	874	935
3 AM	1,079	1,035	973	931	852	944	1,020	967	960	949	876	1,022
4 AM	1,145	1,033	932	937	850	966	1,032	921	910	918	946	974
5 AM	1,013	1,026	945	929	899	963	1,009	913	914	916	908	988
6 AM	1,004	1,044	1,004	936	910	1,042	949	921	977	939	914	988
7 AM	1,047	1,050	984	971	935	971	931	926	1,058	972	986	1,012
8 AM	1,016	1,094	1,067	992	1,009	944	950	957	1,000	982	973	1,009
9 AM	949	996	1,007	1,007	966	966	969	942	992	1,000	996	1,065
10 AM	964	996	1,022	989	932	997	995	1,004	1,011	1,021	972	1,042
11 AM	995	1,038	943	991	947	929	992	981	1,000	973	969	985
12 PM	1,062	1,012	949	1,012	955	934	1,052	1,025	1,031	1,011	940	1,133
1 PM	1,090	1,011	967	1,005	959	962	1,033	1,103	1,085	982	942	1,056
2 PM	989	988	982	957	956	933	1,026	1,055	1,033	1,010	942	1,122
3 PM	991	960	987	968	967	952	1,103	1,086	1,099	992	924	1,049
4 PM	991	971	1,018	997	1,014	1,021	1,070	1,108	1,073	953	955	996
5 PM	1,007	1,021	948	950	966	968	1,147	1,089	1,060	993	1,017	1,084
6 PM	1,038	1,024	983	920	989	992	1,059	1,058	1,038	1,041	1,041	1,043
7 PM	1,014	1,013	992	1,014	965	965	1,091	1,112	1,067	1,070	984	1,092
8 PM	1,010	1,066	1,006	996	969	964	1,000	1,107	1,032	1,029	1,028	1,038
9 PM	1,049	940	1,008	974	951	936	973	1,000	996	959	960	1,014
10 PM	1,064	1,007	989	939	923	990	975	985	1,000	921	938	1,074
11 PM	1,081	1,007	923	1,007	869	1,004	931	916	953	931	875	1,046

Hourly Average System Load (MW)

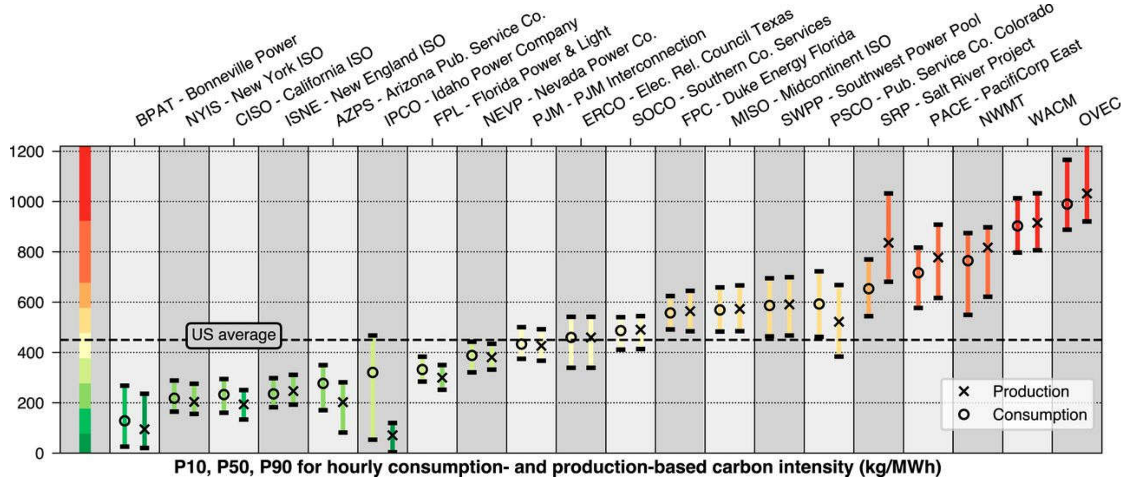
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12 AM	12,860	12,764	11,685	11,065	10,721	11,750	14,197	14,343	12,042	10,678	11,130	12,806
1 AM	12,675	12,592	11,547	10,922	10,475	11,394	13,749	14,016	11,733	10,491	10,921	12,604
2 AM	12,531	12,475	11,459	10,868	10,395	11,262	13,486	13,860	11,628	10,387	10,946	12,522
3 AM	12,563	12,475	11,438	10,864	10,365	11,245	13,281	13,731	11,564	10,327	11,000	12,555
4 AM	12,828	12,738	11,620	11,048	10,497	11,345	13,282	13,755	11,670	10,505	11,200	12,740
5 AM	13,359	13,256	12,163	11,503	10,911	11,603	13,487	14,009	12,105	10,974	11,788	13,269
6 AM	14,492	14,330	13,188	12,336	11,798	12,367	14,133	14,497	12,985	12,053	12,792	14,140
7 AM	15,364	15,109	13,967	13,140	12,683	13,426	15,097	15,382	13,722	12,943	13,587	15,002
8 AM	15,596	15,363	14,143	13,373	13,125	14,113	15,964	16,312	14,247	13,239	13,785	15,347
9 AM	15,658	15,417	14,163	13,456	13,429	14,631	16,825	17,113	14,693	13,375	13,815	15,382
10 AM	15,637	15,396	14,124	13,468	13,646	15,104	17,633	17,909	15,056	13,450	13,814	15,309
11 AM	15,519	15,300	13,975	13,391	13,754	15,471	18,289	18,574	15,307	13,443	13,735	15,208
12 PM	15,374	15,144	13,761	13,228	13,785	15,715	18,755	19,093	15,468	13,388	13,637	15,100
1 PM	15,327	15,063	13,639	13,109	13,840	15,977	19,185	19,593	15,672	13,417	13,638	15,106
2 PM	15,306	14,979	13,522	12,967	13,844	16,143	19,489	19,932	15,818	13,413	13,674	15,148
3 PM	15,502	15,093	13,528	12,935	13,896	16,313	19,693	20,206	16,013	13,510	13,935	15,420
4 PM	16,263	15,564	13,798	13,129	14,074	16,513	19,892	20,456	16,284	13,802	14,739	16,533
5 PM	17,384	16,623	14,313	13,437	14,290	16,633	19,976	20,519	16,472	14,288	15,532	17,422
6 PM	17,365	17,033	14,890	13,676	14,325	16,449	19,676	20,137	16,439	14,866	15,492	17,282
7 PM	16,941	16,636	15,156	14,065	14,327	16,082	19,125	19,625	16,589	14,760	15,069	16,882
8 PM	16,358	16,059	14,811	14,211	14,503	15,866	18,747	19,371	16,088	14,170	14,484	16,346
9 PM	15,417	15,148	13,941	13,418	13,825	15,344	18,064	18,313	15,003	13,244	13,592	15,510
10 PM	14,235	14,025	12,801	12,294	12,553	13,979	16,587	16,755	13,671	12,112	12,500	14,347
11 PM	13,260	13,133	11,942	11,422	11,379	12,630	15,157	15,316	12,554	11,199	11,630	13,350

Hourly Average LMP at NEMA ($/MWh)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12 AM	25	22	16	23	17	17	21	22	22	19	20	43
1 AM	20	23	16	22	17	18	17	22	22	19	18	45
2 AM	21	23	20	22	11	14	16	13	18	16	16	43
3 AM	30	20	13	21	13	15	14	17	15	15	16	43
4 AM	27	24	15	23	11	13	18	21	18	14	19	47
5 AM	25	32	19	25	16	7	18	22	20	17	19	47
6 AM	43	24	23	28	14	9	13	19	29	24	25	56
7 AM	52	28	23	33	20	22	18	25	28	29	29	60
8 AM	40	33	19	31	23	23	22	27	30	28	27	61
9 AM	38	29	17	32	23	22	25	27	28	30	27	57
10 AM	35	28	16	32	24	22	28	30	28	34	25	55
11 AM	36	31	17	29	24	23	33	38	32	32	26	56
12 PM	35	27	17	30	23	25	36	43	35	30	25	49
1 PM	33	28	16	31	24	28	38	57	38	32	23	47
2 PM	32	26	14	28	26	29	46	97	39	31	23	50
3 PM	32	27	13	27	24	29	45	73	42	29	24	54
4 PM	36	28	17	28	29	30	48	93	43	33	33	70
5 PM	53	34	20	31	25	32	53	110	45	37	44	77
6 PM	47	35	22	30	26	29	47	75	40	50	35	68
7 PM	41	32	24	35	30	27	38	40	44	45	29	60
8 PM	40	31	21	37	29	26	37	43	30	32	26	58
9 PM	35	28	17	29	24	26	30	32	25	23	22	56
10 PM	23	25	11	24	19	20	26	26	22	19	22	50
11 PM	20	22	11	22	18	15	18	15	20	17	20	42

But the tables above substantially underestimate the real opportunities because of averaging. Each cell in the table represents the hourly average of an entire month and so obscures much more significant variations which occur on individual days within those months. An expanded heat map table showing all 8,760 hours of a year individually would show more opportunities with intraday differences in Marginal emissions rate as high as 50% or more.

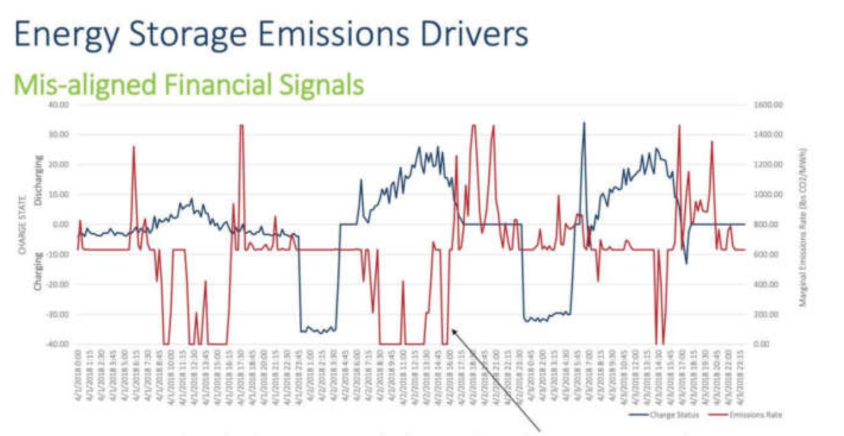
From another report, the chart below from PNAS indicates that the difference between the 10% and the 90% hour in ISO New England, sorted by carbon intensity, is 50% (~290 kg/MWh vs ~190 kG/MWh).



https://www.pnas.org/content/116/51/25497/tab-figures-data

The intraday variation in grid emissions intensity in New England is similar in magnitude to that in CAL-ISO which is useful because this subject has been studied more in CA than in New England. Though there are substantial differences between the CA grid and New England's, many lessons learned in CA may be useful. A 2018 review of California's Self Generation Incentive Program (SGIP) found that in many cases grid financial signals are often misaligned with environmental benefits, and absent thoughtful intervention, means that in some cases energy storage additions to the grid were increasing, not decreasing, total emissions.

For example, the chart below shows energy storage charge status in blue and real time emissions rate in red. From the red line, you can note intraday emissions intensity differences in excess of 2:1 (actually far greater given that marginal emissions rate falls to zero in a number of hours). And yet because the batteries were controlled through economic optimization alone, those low or zero marginal emissions hours correspond often to battery discharging, rather than battery charging. So batteries are charging with cheap (but dirty) nighttime power and discharging at times of peak loads and costs, but relatively low marginal emissions.



Emissions Mis-aligned Behavior: Battery discharging during low emissions periods.

The clear lesson is that given the imperfect coincidence between periods of high cost and high emissions, if you want your energy storage system to reduce carbon pollution, you need to control it that way.

Returning to our pilot, using the same daily load shift per device from energy arbitrage case and using an estimate of 200 lb/MWh and 500 lb/MWh intraday difference in emissions intensity for low and high case respectively, we arrive at the following values for carbon reduction over a 15-year life of a device. Note these reductions are in addition to any reduction from efficiency and fuel switching and represent just the additional reduction from *control* of the devices:

Carbon avoided by load control						
Device	daily load shift (kwhr)	% operating and available	intraday emissions intensity difference (low) lb/Mwhr	intraday intensity difference (high) lb/MWh	15 year carbon savings potential per device (low) lbs	15 year carbon savings potential per device (high) lbs
Heat Pump Water heater	1.2	90%	200	500	1,183	2,957
Air Source heat Pump	1.2	50%	200	500	657	1,643
EV Charger	21	50%	200	500	11,498	28,744
Battery Storage	10	100%	200	500	10,950	27,375

Further Considerations

The Smart Grid Pilot project has yielded many useful insights into both technology options as well as customer acceptance which we hope will provide a foundation for future pilots or programs by Efficiency Maine. As an early stage innovation pilot, the program also elevated a number of useful questions which we hope Efficiency Maine and other stakeholders will consider as we think about next steps with respect to DER aggregation and control in Maine. Below are a handful of topics we believe are worthy of additional discussion, investigation and learning. We do not attempt to answer the questions here, but just raise them as topics worthy of further consideration by policy makers and program administrators in the future.

How can programs like this work in deregulated electric markets like we have in Maine?

From our review of programs around the country we found that most of the DER programs and pilots are taking place in markets where customers are served by either vertically integrated utilities or by consumer or municipal cooperatives. For example, Green Mountain Power in VT has been a leader in deploying customer sited DERs and managing them for the benefit of ratepayers. Sacramento Municipal Utility district (SMUD), Belmont light and Washington Electric Coop are other national leaders in this area. When compared to Maine's investor owned utilities, these entities have the benefit that they can monetize savings on behalf of ratepayers whether they are on the Generation (capacity, energy price suppression, etc) or Transmission and Distribution (reduced RNS, NTA, etc) side of the ledger. In Maine, on the other hand, the investor owned utilities only provide T and D and do not sell electricity to customers, so they would have to cooperate with an energy supplier like the Standard Offer provider to capture the full value of aggregated DER control.

With a historical focus on programs implemented and devices installed behind the customer meter, and a fairly sophisticated understanding of energy markets as a whole, Efficiency Maine may be a better fit for managing these programs in Maine. Though beyond the scope of this report, it is worth considering whether existing authority is sufficient or what additional legislative or regulatory mandate might be required for Efficiency Maine to do that most effectively on behalf of Maine ratepayers.

What is the appropriate Role for the Monopoly T and D utilities in these programs?

Historically, electric Utilities have been granted a monopoly franchise based on the logic that the utility business is a 'natural monopoly' and thus customers benefit from that arrangement due to economies of scale. Increasingly, it is clear that some of the functions historically performed by utilities may be performed better and more cost effectively by competitive providers in a free market. We experienced that a few decades ago when Maine and most of New England deregulated the generation side of the electricity market and provided opportunity for private capital and innovation to compete, as well as more recently as the legislature has delegated responsibility for assessing and designing NWA solutions to the NWA coordinator in the OPA's office. Aggregation and control of DER's is likely another example where private enterprise and competitive markets will yield better results for customers, however there is clearly a role for the legacy utility companies to play. As Maine develops policy for encouraging the adoption of flexible, controllable and aggregated DERs, policy makers and program administrators will have to answer what that role should be. Do we want utilities to compete with unregulated entities and own devices behind customer meter? Should the utility own the DERM platform and provide control for devices owned by others? Should the utility provide a platform for third party aggregators and be responsible for dispatch decisions? Or should the utility be wholly uninvolved and allow an independent entity (like Efficiency Maine or the NWA coordinator) to fulfill these roles?

How can/should the DER aggregation and control role interface with the new NWA coordinator role?

As Maine finally stands up an independent NWA coordinator, nearly ten years after the successful Boothbay pilot project, it is worth exploring how the operator of DER aggregation platform, perhaps inside Efficiency Maine, should collaborate with that NWA coordinator. A joint study earlier this year from California's three major utilities found that the combination of solar plus storage could yield an 'effective load carrying capacity' (ELCC) of nearly 1! That finding has dramatic implications for the applicability of solar + storage to meet a variety of grid investment needs and should inform both the work of the NWA coordinator and DER aggregator in Maine going forward: https://www.pv-magazine.com/2020/07/20/solar-plus-storage-has-a-99-8-capacity-value-in-california/

Is Maine ready for a BYO battery or other device program?

A number of New England States have developed statewide or utility specific 'bring your own device' type programs for residential energy storage and other smart appliances. Massachusetts, New Hampshire and Vermont now all have programs of some kind, whether statewide or an individual utility pilot.

In advance of the 2020 legislative session, the legislature convened an Energy Storage Commision to provide recommendations to the EUT committee regarding targets, technologies, programs and goals related to energy storage. In its final report, the Commission made nine recommendations and among them was "Advance Energy Storage as an Energy Efficiency Resource." The Commission heard that Efficiency Maine already has the statutory authority to implement such a program and though the 2020 legislative session was cut short by the corona virus public health emergency and so no additional directive was provided, it would be useful for Efficiency Maine to consider whether such a program fits within its existing legislative mandate.

As Maine makes investments in electrifying transport, how will we ensure that the newly electrified load reduces, rather than increases, costs for all ratepayers?

Though the pilot's findings with respect to EV charging was mixed (load is substantial, but utilization of chargers was low and not necessarily peak coincident), the sheer magnitude of new load represented by electrification of transport means that this has to be an area of focus for policy makers. While this pilot considered 'what is the value of the large dispatchable load that is a level 2 EV charger?' another way to ask the same question is, 'what is the cost to ratepayers if we add these loads in a way that is unmanaged?' And clearly the answer is that the cost may be substantial. As Efficiency Maine rebates, Utility pilot projects and other state programs in support of transportation electrification enable substantial public investment over the coming years, it is worth understanding the pros and the cons of 'smart charging' and also investigating whether the 'smarts' will be in the charger, the vehicle, or both.

How can we ensure that programs that support load flexibility are available equitably to customers of all kinds?

When load is controlled and peak energy consumption and costs are lowered, all ratepayers benefit. However, we need to be deliberate about ensuring those benefits are shared equitably among ratepayers. If programs are designed to share some portion of benefits specifically with participating ratepayers to provide an incentive towards a particular action, we need to be cognizant of whether all ratepayers have an equal opportunity to participate. For example, if lower income Mainers are less likely to have a heat pump or a smart thermostat, will they have equal opportunity to participate in a program that compensates them for control of those devices? As policymakers build programs to advance electrification and specifically advanced controls, care must be taken to ensure they are providing both opportunity and benefits to all types of ratepayers.

What is the appropriate way to manage concerns about data privacy concerns in these programs?

Utilities and regulators have historically taken their obligation to maintain customer privacy very seriously. In an era of increasing competition and collaboration between utilities and other energy service providers, the historical data privacy rules and practices of the legacy utilities has sometimes become a barrier to innovation and competition. As homeowners play an increasingly active role as energy market participants, and not just customer, we will need to adopt a new set of market rules and norms regarding customer data and privacy. This begins with acknowledging that a customer's energy usage data belongs to them and that all market participants (whether utility or non-utility) should be held to the same rules when it comes to privacy and security.

REVISION ENERGY

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We thank you for the opportunity to collaborate on this interesting and exciting pilot project. In spite of some of the challenges posed late in the year by the COVID-19 pandemic and related disruptions, the pilot has been a success and generated data and insights that we hope will be useful for Efficiency Maine and other stakeholders as you evaluate the growing potential of load flexibility from aggregated behind the meter DERs.

Thank you for your support and help during this pilot and for your leadership in Maine's clean energy transition.

Respectfully submitted:

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